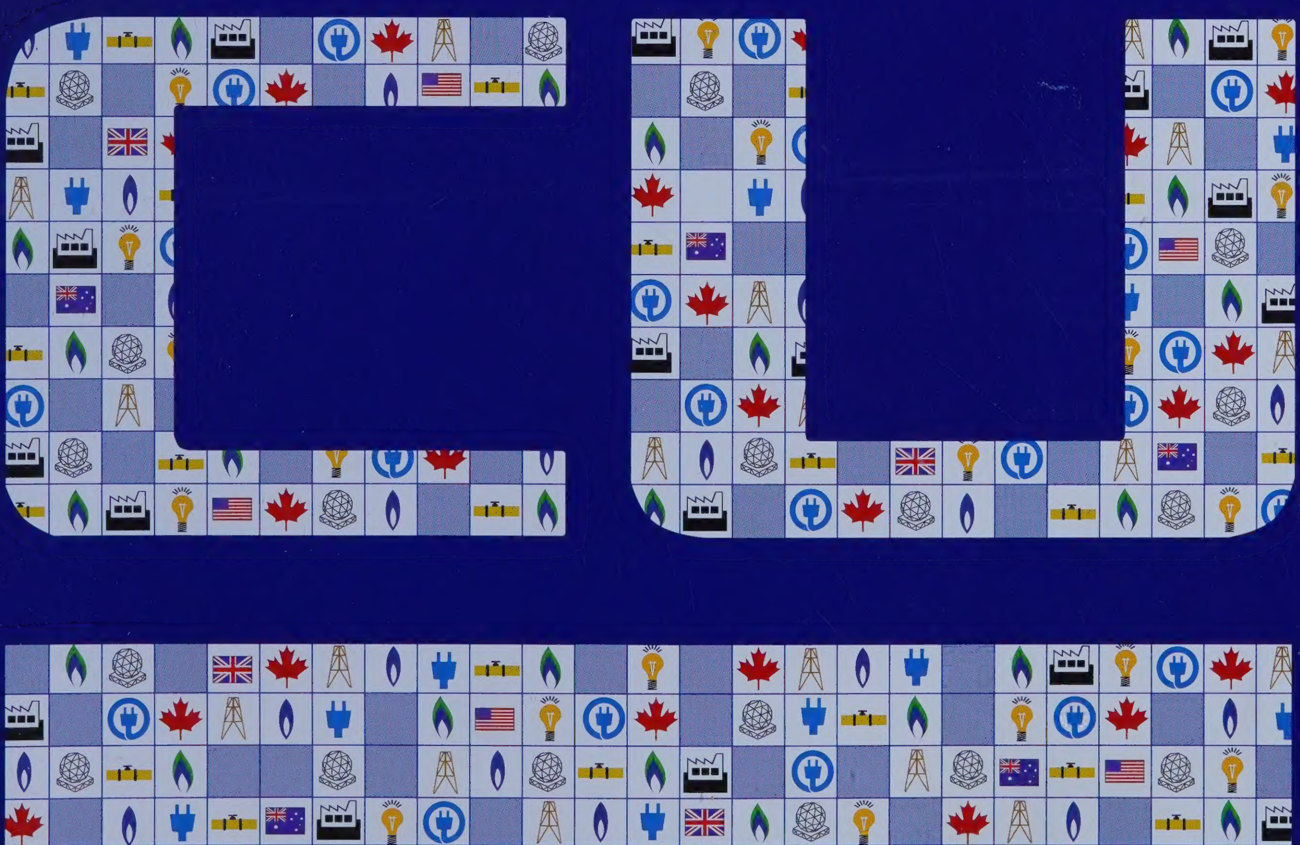
CANADIAN UTILITIES LIMITED

An ATCO Company

ANNUAL REPORT 2004



CANADIAN UTILITIES LIMITED CLASS A NON-VOTING AND CLASS B COMMON SHARES

FIVE YEAR TOTAL RETURN ON $100 INVESTMENT

	Compound Growth Rate	Cumulative Return
Class A Non-Voting	13.4%	$187
Class B Common	14.5%	$197
S&P/TSX Composite Index	3.5%	$119
S&P/TSX Utilities	19.3%	$242

The graph compares the cumulative share owner return over the last five years on the Class A Non-Voting and Class B Common shares of the Corporation (assuming the reinvestment of dividends) with the cumulative total return of the S&P/TSX composite index and the S&P/TSX utilities index.

Consolidated Annual Results

(Millions of Canadian Dollars except per share data)	2004	2003
Financial		
Revenues	3,089.5	3,742.6
Earnings attributable to Class A and Class B shares	309.0	259.1
Total assets	6,463.1	6,096.5
Class A and Class B share owners' equity	2,117.7	1,948.5
Cash flow from operations	538.3	525.8
Purchase of property, plant and equipment	535.5	495.7
Class A Non-Voting and Class B Common Share Data		
Earnings per share	4.88	4.09
Diluted earnings per share	4.86	4.07
Dividends paid per share	2.12	2.04
Equity per share	33.41	30.74
Shares outstanding (thousands)	63,392	63,384
Weighted average shares outstanding (thousands)	63,383	63,389

Consolidated Quarterly Results(1)

(Unaudited)

(Millions of Canadian Dollars except per share data)		Three Months Ended				
		March 31	June 30	Sept 30	Dec 31	Total
Revenues	**2004**	**1,185.9**	**690.2**	**550.8**	**662.6**	**3,089.5**
	2003	1,372.2	797.5	622.6	950.3	3,742.6
Earnings attributable to Class A and Class B shares	**2004**	**74.5**	**100.2**	**44.0**	**90.3**	**309.0**
	2003	85.9	43.5	43.2	86.5	259.1
Earnings per Class A and Class B share	**2004**	**1.17**	**1.58**	**0.70**	**1.43**	**4.88**
	2003	1.35	0.69	0.68	1.37	4.09
Diluted earnings per Class A and Class B share	**2004**	**1.16**	**1.58**	**0.70**	**1.42**	**4.86**
	2003	1.34	0.69	0.68	1.36	4.07

(1) Because of seasonal fluctuations, particularly in the utility operations, quarterly earnings are not indicative of full year results.

TO THE OWNERS OF OUR CORPORATION

Ladies & Gentlemen:

2005 marks Alberta's Centenary and it is notable that Canadian Utilities Limited (CU) has been a part of building its home province for 96 of those 100 years.

Canadian Utilities' journey has been marked by many accomplishments over the decades, always guided by our definition of Excellence....

Going far beyond the call of duty .... maintaining the highest standards .... looking after the smallest detail .... doing more than others expect .... and caring.

Our Commitment to Excellence has been nurtured through the years by the leaders of your company and today it is ingrained in everything we do – from operations – to financial responsibility – to the governance of our businesses.

OUR COMMITMENT TO EXCELLENCE HAS BEEN NURTURED THROUGH THE YEARS BY THE LEADERS OF YOUR COMPANY AND TODAY IT IS INGRAINED IN EVERYTHING WE DO

Your President's Message, which follows, reports on the operational and financial performance for Canadian Utilities. As Chairman of your Board of Directors, I am pleased to report on the fundamentals of our governance.

Canadian Utilities Limited is compliant with recently mandated changes for all Canadian publicly traded corporates in 2005, and will be compliant with the proposed changes required in 2006.

The workload for Officers and Directors alike has been enormous in this transitory period, but when we survey the whole, we are pleased with the outcome.

The form is what I refer to, but your Board has always understood and remains absolutely dedicated to:

- the approval of strategic directions for each of the units making up Canadian Utilities;
- the oversight of, and planning for, the succession for all key executives who provide our leadership;
- the preservation of our industry leading credit rankings;
- the protection of capital for expansion and the safeguards for high performance sustainability;
- risk management oversight;
- health, safety and environmental stewardship.

Governance in CU, together with four sub group Boards, has many important facets which deliver best practices.

Our Directors, Chairman and members of our various committees, together with our Lead Director and DADs (Designated Audit Directors) have met for a total of 35 days this last year. In addition, their preparation, study and special background work, together with special assignments, consultations, and travel would match or exceed their formal days of effort.

A full reading of our management's discussion and analysis will provide you with more detail, but I would also highlight for you that CU policies have been reviewed this year from the standpoint of need, and clarity; a streamlining initiative is underway with respect to governance and procedural processes; project presentations for capital requests have been totally reviewed and appropriate policies have been issued along with a detailed manuscript on lessons learnt, spanning many decades of experience.

Canadian Utilities' statutory By-laws pertaining to the Canada Business Corporations Act have been reviewed and updated. By-laws will be presented to our Share Owners for approval at our forthcoming Annual General Meeting.

Much attention has been given to our internal controls and we will become totally compliant with the new regulations mid 2006, and our disclosure and communications policies and procedures are all in place.

I personally would like to thank our Directors on behalf of all our Owners for their dedication and caring. Individually they are outstanding, and as a group they bring formidable knowledge, experience and dedication to our governance.

We wish to thank retiring Directors, Larry Shaben and Logan Tait. They have brought the ATCO heart, mind and spirit to all their deliberations, always, on your behalf. Together they have brought 37 years of commitment to our group of Companies, and they truly have been a source of enlightenment and advice for our people.

May I also thank each and every one of the owners of our shares for your encouragement and belief in our efforts.

Respectfully submitted,
On behalf of the Board of Directors,

R.D. Southern
Chairman

PRESIDENT'S LETTER TO CU SHARE OWNERS:

Record accomplishments by many of our companies and the achievement of significant business milestones marked 2004 as Canadian Utilities Limited pursued operational efficiencies and a disciplined growth strategy that delivered:

- Increased earnings and earnings per share for the 15th consecutive year, (excluding gain on sales of retail energy services and the Viking Kinsella properties)
- An 8¢ dividend per share for the 32nd consecutive year.
- $90 million sale of retail energy services
- $500 million 10-year ATCO I-Tek customer care and billing services contract
- Shareowners equity of $2.1 billion

In previous Annual Reports, I have explained part of our growth strategy is identifying, unbundling and monetizing assets that have negligible impact on earnings in both our Utility and Global Enterprises companies.

Our ongoing objective each year is to analyze, on a separate and distinct basis, the lowest performing assets and dispose of them when the opportunities present themselves. The $90 million sale of our energy supply business in our utilities is an example of this strategy. This was the service of purchasing natural gas and electricity on behalf of industrial, commercial and residential customers in ATCO Gas and ATCO Electric. The regulator disallowed us a rate of return for performing this function, even though, on occasion, we had been required to inject significant capital on a no return basis in high energy cost periods. Deregulation has allowed us to carve out this function and complete the $90 million sale to Direct Energy in May 2004, which contributed additional cash to our already strong balance sheet.

More importantly, the retail sale was accompanied by the $500 million contract that Direct Energy signed with ATCO I-Tek, which will generate about $50 million in revenue per annum and considerable earnings over the 10-year life of the contract.

Strong fundamentals in the economies where Canadian Utilities operates translated into high activity levels and good growth opportunities for each of our principal operating subsidiaries.

- ATCO Power has reached an agreement with respect to their claim against TXU's insolvent power purchase agreement at the Barking plant in London, England.
- ATCO Midstream achieved record earnings, which were attributable to a focused concentration on operational excellence, resulting in greater plant availability and increased volumes throughout the year.
- ATCO I-Tek completed the seamless transfer of the "retail sale" customers to Direct Energy.
- ATCO Frontec increased its base of operations with NATO and secured the Kabul Airport facilities management contract in Afghanistan on January 31, 2005.
- ATCO Gas, ATCO Electric and ATCO Pipelines experienced record new customer hook-ups and installations, which are forecast to continue in 2005.

For many years, we have pursued strategic initiatives in the North. In 2004, a number of our companies, lead by ATCO Frontec, made good progress, together with our aboriginal partners, in developing an initiative to assist and cooperatively work with MacKenzie Valley Pipeline Producers Group.

Canadian Utilities' aboriginal joint ventures are partnerships of mutual respect and contribution, forged with the objective of providing our customers with housing, fuel, facilities management, power generation, heating, security, gas gathering systems and transportation across the North.

I want to especially thank our joint venture partners, Panarctic Inuit Logistics (Nunavik, Nunavut, Inuvialuit, Labrador Inuit), Denedeh Development Corp., Nunasi, Inuvialuit Development Corp., Yukon Indian Development Corp., the Dogrib, Piikani and the Inupiat of Alaska as our combined efforts have created confidence and appreciation for delivering significant value to our many clients.

As we look to the future, each of our companies has good opportunities for generic growth in the jurisdictions they serve, and all have enterprising new growth prospects.

It is precisely for such opportunities that we have worked long and hard to improve our cash on hand and to strengthen our balance sheet so we can move with full force when the right opportunities come available.

Our objective is to maintain a range of 60-75% of our business mix in regulated utilities. Currently, our regulated versus non-regulated mix is about 65/35%, with the legacy power plants of Alberta Power 2000 included as regulated business under the power purchase arrangements.

As we pursue key growth opportunities in 2005, we will also launch a major corporate initiative to celebrate Alberta's centennial. We have manufactured a traveling caravan comprised of three mobile units that will be filled with artifacts, pictures, displays and exhibits that describe the role ATCO and Canadian Utilities have played in the development of Alberta.

Over a four month period, our caravans, accompanied by the Lord Strathcona's Mounted Troop and other special features, will visit 50 Alberta communities, spanning the width and length of Alberta.

Finally, as you may be aware, much of my focus for the past two years has been on leadership succession detail. Large scale recruitment and development drives to replenish and renew our people have been largely accomplished in 2004, which is why your Board and I are so happy to report that Canadian Utilities Limited, entering 2005, reflects a new generation of leaders notable for their extensive experience within our companies.

To a man and woman, they march in the first rank of competency, dedication and enthusiasm. Their great work ethic is a delight to witness as fresh and determined execution takes hold precisely because they bring with them the our definition of "Excellence".

Canadian Utilities has 6,000 people, and I would like to thank each of them, every one, for their perseverance and achievements. I would also like to thank our Board of Directors and the many owners of our shares for your confidence and support.

I hope you will find this year's annual report interesting and even more informative than in the past. As to the future, smooth courses may not always be open to us, yet if you look closely at our positioning, our people and our past record, I do believe you will agree that our prospects for a bright future are encouraging.

I look forward to seeing you at our Annual General Meeting.

N.C. Southern

N.C. Southern
President & Chief Executive Officer

OFFICE OF THE CHAIRMAN

(left to right)

Michael M. Shaw - Managing Director, Global Enterprises

William L. Britton - Vice Chairman of the Board

Susan R. Werth - Senior Vice President & Chief Administration Officer

Ronald D. Southern - Chairman of the Board

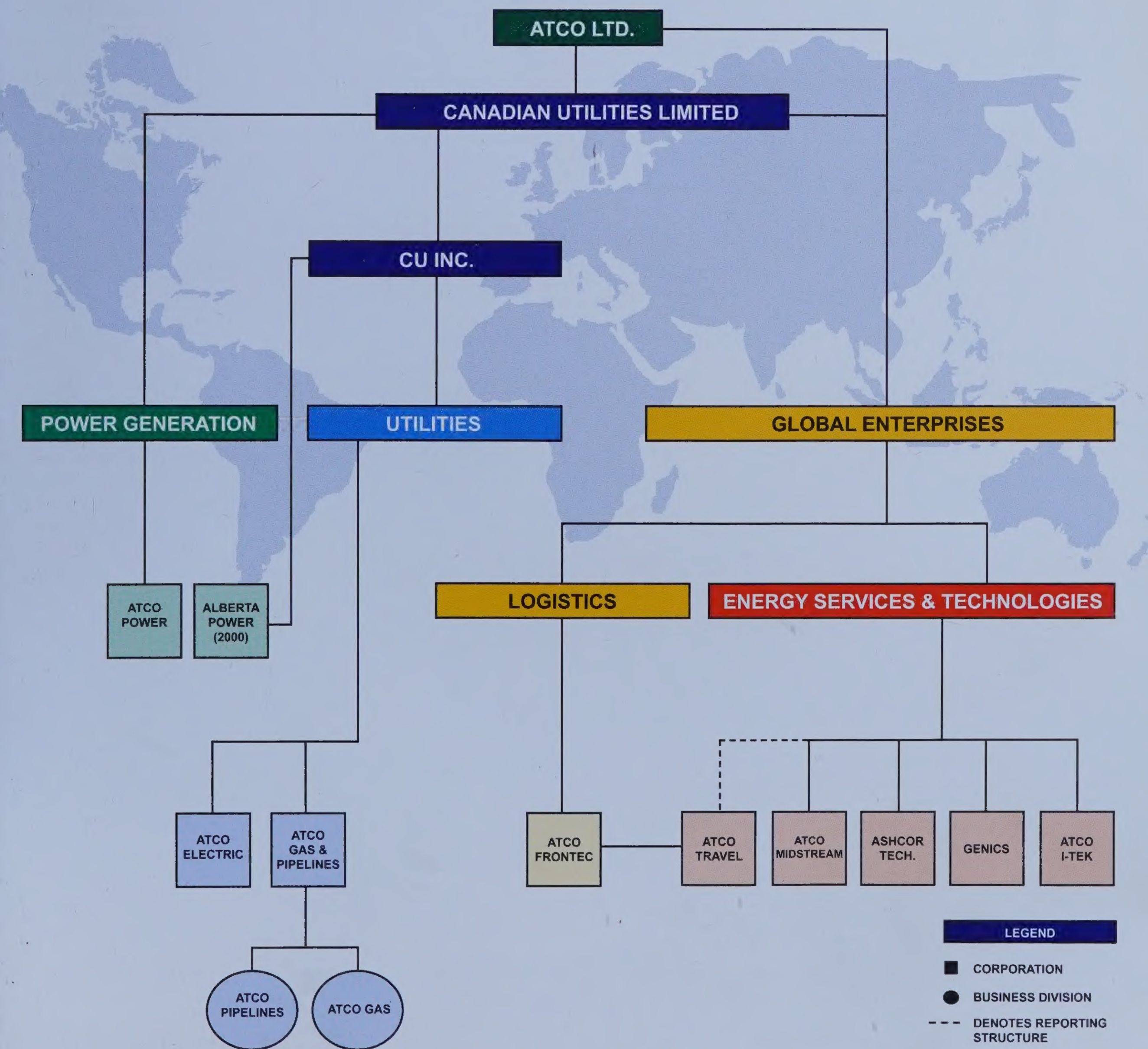
Karen M. Watson - Senior Vice President & Chief Financial Officer

Nancy C. Southern - President & Chief Executive Officer

Siegfried W. Kiefer - Managing Director, Utilities and Chief Information Officer

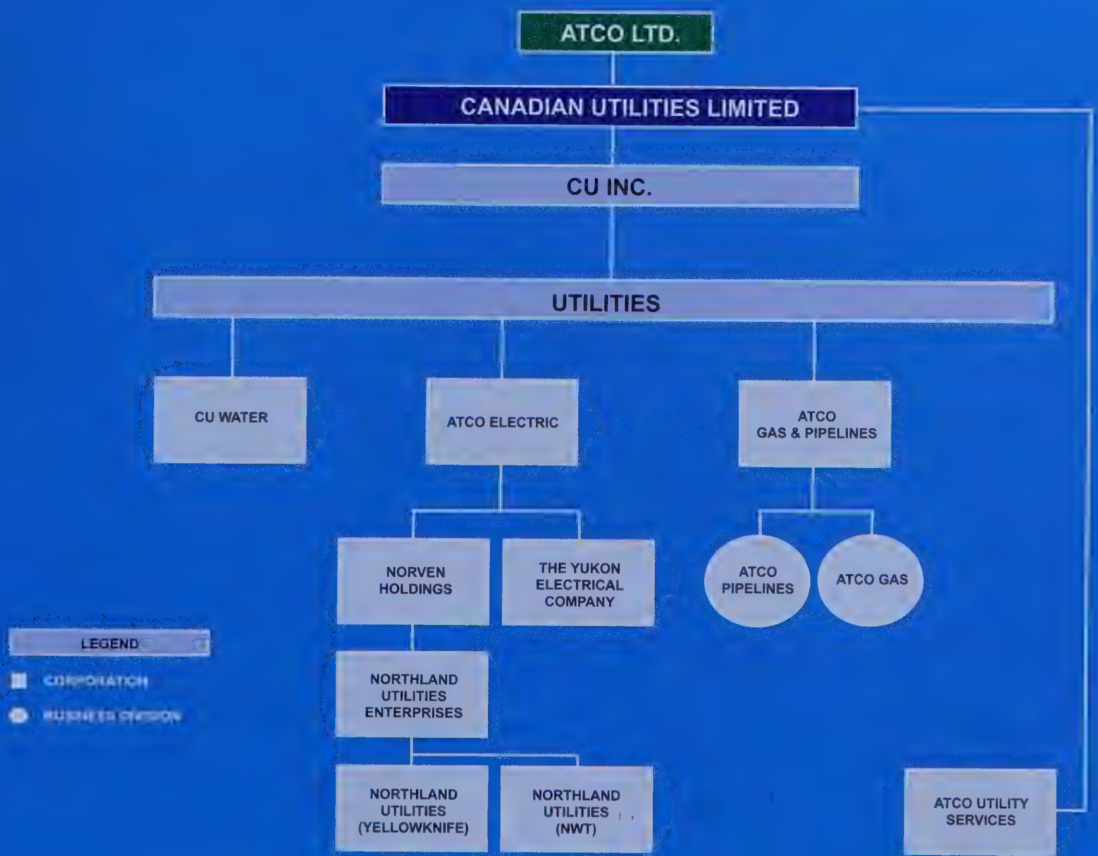
Business Groups

Canadian Utilities Limited, a premier international corporation, Alberta based, delivers distinguished world class performance, profitable sustainable growth, community partnerships and value creation strategies through operational excellence.



Canadian Utilities' considerable investment in infrastructure ensures customers enjoy safe, reliable utility service 24 hours a day.

Utilities Group



◄ Photo: ATCO Pipelines replaced 4 km of the original Turner Valley #2 transmission line to ensure reliable natural gas service to customers served by this pipeline. Crews are shown stringing a joint of pipe in preparation for welding the new pipeline.

Photo: Grande Prairie serviceman Dave Makarenko is one of the 900 ATCO Electric employees devoted to providing safe, reliable delivery of electricity to Alberta customers. Twenty-four hours a day, 365 days a year, ATCO Electric is ready to respond.

The Utilities Group remains committed to the communities we serve by operating regional offices and service centres throughout the province.

UTILITIES GROUP

The Utilities Group experienced record levels of capital expenditures in 2004 due to Alberta's robust economy and growing population. Significant expansion of the province's oil and gas industry is attracting large investments and new workers, particularly in the Grande Prairie, Fort McMurray and Lloydminster areas. This tremendous growth is driving the need for increased and improved natural gas, electric and water infrastructure.

A significant milestone for the Utilities Group in 2004 was the seamless transfer of more than one million retail customer accounts from ATCO Gas and ATCO Electric to Direct Energy Regulated Services. Now that responsibility for purchasing energy and billing customers has been successfully transferred, our energy utilities are focusing on their core business of building and maintaining safe, reliable natural gas and electricity delivery systems for residential, farm, commercial and industrial customers across Alberta.

Canadian Utilities' commitment to Operational Excellence and considerable investment in our utility companies to maintain and improve the reliability of the utilities' infrastructure, ensures that customers enjoy safe, reliable service every hour of the day and night.

Our companies' responsibilities continue to include efficient and dependable emergency response to service interruptions and meter reading. ATCO Gas continues to provide in-home services such as safety checks for natural gas furnaces and appliances.

ATCO Electric

ATCO Electric's focus in 2004 was on its core business of transmission and delivery of electric energy to its customers.

The continued expansion and development of the oil and gas industry in northern Alberta, particularly in the Grande Prairie, Fort McMurray and Lloydminster areas, kept ATCO Electric very busy in 2004. The company spent a record $214 million on capital projects to upgrade, maintain and improve our system, which includes 9,100 kilometres of transmission line and 56,000 kilometres of distribution line.

ATCO Electric delivers safe, reliable electric energy to more than 182,000 customers in more than 238 communities, Aboriginal reserves and Métis settlements across northern and east-central Alberta. In 2004 we transmitted nearly 9.9 million megawatt hours of electricity.

Above all, ATCO Electric remains committed to the highest level of customer service. The company made impressive strides towards enhancing customer service by working with the Alberta Energy and Utilities Board (EUB) to set up processes and procedures to meet EUB service quality requirements.

One of the company's more significant projects in 2004 was the completion of the $99 million Dover-Whitefish transmission line that boosted electric energy transport capacity in northern Alberta by 250 megawatts – from 350 megawatts to 600 megawatts. In addition to being the third major line between Fort McMurray and Edmonton, three new substations were added to accommodate energy plants being built in conjunction with new oil sands projects in the region. The 350-kilometre transmission line was completed in record time amid great construction challenges including harsh temperatures, muskeg, and rugged terrain.

The project also showcased our commitment to protection of the environment. In an effort to return animals displaced by the transmission line construction, ATCO Electric built 70 furbearer houses from debris along the transmission line right-of-way. The piles of wood and branches provide shelter to wildlife affected by this project.

ATCO Electric hosted the second annual REA Conference for Rural Electrification Associations (REAs) in our service area. The conference served as an excellent forum for information sharing and relationship building. Relationships between ATCO Electric and REAs are positive.

ATCO Electric also strengthened its relationships with Aboriginal people in 2004. In addition to working closely with several Aboriginal groups and contractors on the Dover-Whitefish transmission line, the company signed a partnership letter with Concordia University College. The partnership is aimed at working more closely with their Aboriginal University and College Entrance Program (UCEP) in Edmonton. We also signed an agreement with the Aseniwuche Winewak Nation (AWN) in the Northwest Region, outlining how we will work together in the future. AWN represents the interests of about 450 Aboriginal people who live on cooperatives north and west of Grande Cache.

The agreement paved the way for an opportunity to collaborate on an innovative, environmentally friendly solution to mechanical tree clearing. Aseniwuche Development Corporation, ATCO Electric and Parks Canada used logging horses to thin about 5.7 hectares of forest in an environmentally sensitive area in Jasper National Park. Under the direction of Parks Canada, the team cleared trees to reduce the risk of wildfire between an industrial plant and ATCO Electric's Palisades Plant. This work will help maintain the Town of Jasper's power supply in the event of uncontrolled wildfire in the area.

▼ Photo: Safety is the number one priority at ATCO Gas. More than 1,800 dedicated ATCO Gas employees are committed to ensuring the natural gas system is safe and reliable. Nearly one million customers depend on ATCO Gas for their natural gas service every day.

In 2004 ATCO Electric marked the second year of a three-year project to remediate 77 operating and decommissioned isolated generation plant sites. With 21 sites now cleaned up, the project is now 70% complete. These sites will be available for future uses as they are restored to standards required for residential/parkland use, which are more stringent than requirements for commercial and industrial sites.

With most customers now receiving actual meter readings every month thanks to automated meter reading devices, ATCO Electric found an opportunity to explore a new meter technology to help customers reduce electricity use and contribute to a cleaner environment.

ATCO Electric, in partnership with Natural Resources Canada and InfoEnergy, launched a pilot project to test smart metering in Drumheller and Grande Prairie in 2005. The pilot is the first of its kind in western Canada and allows customers to pre-purchase their electricity, load their credits into the smart meter, and use an in-home display unit to know exactly how much electricity they are using at any given time.

NORTH OF 60 COMPANIES

Active economic activity was not limited to Alberta in 2004. ATCO Electric subsidiaries in Canada's North are experiencing steady growth driven largely by the diamond industry, renewed interest in gold exploration, increased government and retail activities and the potential of a Mackenzie Valley Pipeline.

Northland Utilities

Northland Utilities (NWT) in Hay River renewed its franchise agreement, while Northland Utilities (Yellowknife) Limited received a Public Utilities Board permit and license to convert Yellowknife's distribution system from 5 kV to 25 kV – an eight year, $17 million program.

Yukon Electrical

The Yukon Electrical Company has been providing electrical service to Yukoners for over a century. Chartered in 1901, Yukon Electrical has grown to serve 13,500 customers in 20 communities from south of the Yukon border to north of the Arctic Circle.

ATCO Gas

ATCO Gas kept pace with Alberta's expanding economy in 2004, spending a record $154 million on capital projects, adding 564,000 metres of pipe to the distribution system, bringing natural gas service to 26,580 new customers, and operating and maintaining more than 34,800 kilometres of distribution pipelines. As at December 31, 2004, the company was serving 914,347 customers in 291 communities throughout Alberta.

Franchise renewals were a priority in 2004 and ATCO Gas successfully renewed 61 franchise agreements, including the City of Edmonton, most using a template developed with the Alberta Urban Municipalities Association.

In 2004, ATCO Gas completed 591,934 jobs and 455,163 service calls for our customers. These jobs included equipment and appliance inspections, meter installations and moves, emergency response to gas odours and carbon monoxide, and requests to re-light appliances.

As the province's growth and demand for energy distribution continues to increase, ATCO Gas has responded by finding safe, reliable and efficient ways to meet the needs of customers.

ATCO Gas was the driving force behind the development of four-party trenching – a program that allows the four utility companies to install natural gas, electricity, telephone and cable mains and services into a single trench all at the same time.

ATCO Gas piloted this construction method in Calgary in the late 1990s, and although other areas of the province have since moved to four-party trenching, Calgary is the only major centre in Alberta where this construction method is the standard.

In 2004 all of Calgary's new residential subdivisions – about 8,500 lots – were completed using four-party trenching. Another 1,500 lots throughout the province were completed this way, mostly in Fort McMurray, Lethbridge and Grande Prairie.

The housing construction boom presented other challenges for ATCO Gas that were quickly addressed. For example, in the Southeast Planning Area of Calgary, Auburn Bay required gas

service by the end of 2004 while the community of Seton will require gas service in the summer of 2005. There were no gas mains in close proximity to these communities. As a result, neither temporary nor permanent gas service was available without the construction of a significant feeder main.

ATCO Gas responded with a $2.2 million project to extend a feeder main to Auburn Bay and Seton. The feeder main not only forms part of the long-term gas supply to the Southeast Planning Area, but provides a secondary gas supply to the community of Cranston, increasing the reliability of gas service to these customers. Construction began on October 22 and was completed on December 4, 2004.

The Meter Relocation and Replacement Program also continued in 2004. Over time the program will move 200,000 residential gas meters outside customers' homes and replace them as required in an effort to improve safety, efficiency, accessibility to meters, and meter reading accuracy.

In 2004, more than 16,000 meters were moved from inside customers' homes, bringing the total to nearly 33,000 meters moved since the program began in 2003. The program is expected to take eight more years to complete.

As ATCO Gas continued its focus on the safe, reliable delivery of natural gas, it also increased its attention on public safety programs to educate customers about the risks involved with living and working around natural gas. ATCO Gas continued its ongoing support and partnership with "Alberta One-Call" to encourage customers to "Dig a Hole Lot Smarter" and have underground utilities properly marked before they do any digging.

Customers were also reminded to have their natural gas appliances inspected annually, and to check for uncapped gas lines around their homes and garages. In addition to advertising, ATCO Gas took the added step of working with moving companies, realtors, and appliance retailers to inform customers about uncapped lines. In 2004, customers were also informed about how to respond to gas odours and carbon monoxide leaks in their homes. Employee and customer safety will continue to be a company priority in the years ahead.

Another priority for ATCO Gas is to participate in innovative projects that deliver energy more efficiently and lower greenhouse gas emissions. In 2004, ATCO Gas saw its $1.2 million commitment to a hydrogen fuel cell research project at the Northern Alberta Institute of Technology (NAIT) make an immediate first impression.

The fuel cell is the first commercial high-voltage fuel cell in Canada. Not only does it supply 10% of NAIT's electricity requirements, and heats the swimming pool and water for showers at its main Edmonton campus, it also provides a unique learning opportunity for the next generation of electrical and mechanical engineers.

Looking ahead, ATCO Gas continues to work with communities to invest and participate in other alternative energy projects in the province that involve district energy systems, fuel cells, and thermal energy.

ATCO Gas has a long history of safe and reliable service to its customers, and with its increasing interest in partnering on innovative energy projects, the company is well-positioned to be a key player in the development of energy distribution systems of the future.

CU Water

CU Water owns and operates a water transmission line from Sherwood Park, Alberta to Viking, Alberta. In addition, several lateral lines serve rural subdivisions and five intensive livestock operations. The Town of Tofield and the Town of Viking are two of the company's largest customers.

The company also owns and operates the water distribution system in the Village of Ryley and in 2004 completed the purchase of the water distribution system for the Village of Holden.

ATCO Pipelines

ATCO Pipelines operates a natural gas pipeline system of more than 8,330 kilometres connecting producers with Alberta markets and providing interconnections with all major export pipelines.

▲ Photo: ATCO Electric owns and operates a sprawling system of high and low voltage power lines that deliver electric energy to Alberta homes and businesses. ATCO Electric linemen receive specialized training to perform live-line work as a way of minimizing power interruptions for customers.

With this significant infrastructure, ATCO Pipelines is well positioned to provide shippers access to markets of their choice.

Alberta's robust economy helped ATCO Pipelines reach its highest level of capital expenditures in three years.

Continued oil sands development in the Fort McMurray region provided opportunities for ATCO Pipelines to expand its business in this market. ATCO Pipelines began supplying a new customer, Deer Creek Energy Limited, with volumes from the Muskeg River pipeline and is negotiating with other potential customers in the area.

ATCO Pipelines added new compression facilities to its system in 2004 to increase receipt transportation capacity and security of supply. Construction was completed on the Sturgis #2 compressor on the Ranfurly transmission pipeline and at Noel Lake on the Swan Hills transmission pipeline. A new compressor was also installed on the Alliance Pipeline transmission system north of Grande Prairie.

ATCO Pipelines built three new pipeline interconnections during 2004 to facilitate access to markets. Construction of two interconnections with Alliance Pipeline transmission system, one north of Grande Prairie and another at Irma was completed. An interconnection to ATCO Pipelines' Cardston transmission pipeline was also completed.

ATCO Pipelines' Integrity Program to ensure the ongoing safe operation and service reliability of the company's pipeline system continued in 2004. A relocation of a segment of the Jasper transmission pipeline in Jasper National Park to ensure security of supply to the Town of Jasper and other

▲ Photo: Lighting up the North – Christmas lights in downtown Yellowknife, NWT, symbolize CU's 'North of '60' companies' commitment to the north. Together, Northland Utilities and Yukon Electrical have over a century and a half of service to communities across the Yukon and NWT.

customers in the Park was completed. An exposed section of the Taber-Coutts transmission pipeline under the Chin Lake reservoir was replaced by directional drilling. Approximately 4 km of the Turner Valley transmission line, originally built in 1925, was replaced to ensure reliable natural gas service to customers served by this pipeline. The Grande Cache transmission pipeline required relocation work to ensure the security of gas supply to the Town of Grande Cache. A 273 mm pipeline was also installed between the Dow Hydrocarbon and Dow Chemical plants in the Fort Saskatchewan area to provide customer requested security of supply for each site.

The capital phase of the Unaccounted For Gas (UFG) meter installation projects that began in 2001 was completed late in 2004. Approximately 1,200 new flow meters were installed between ATCO Pipelines' high pressure lines to ATCO Gas' intermediate pressure regulating stations. The Meter Installation Program was undertaken to provide custody, transfer-quality metering for the majority of loads delivered to ATCO Gas.

ATCO Pipelines received EUB approval for a new rate structure which was implemented November 1, 2004. The new rates are cost-based and provide competitive rate options to access both supply and markets on ATCO Pipelines' North and South systems. The prior rate structure was the result of negotiated agreements while the new rates represent the first extensively tested rate structure for ATCO Pipelines.

Continued strong oil and gas prices are stimulating new investment in oil sands development, conventional gas drilling and Coal Bed Methane (CBM) development, all of which provide opportunities for ATCO Pipelines. High gas prices for industrial customers, however, increase feedstock costs and reduce their competitiveness in the global marketplace, which increases ATCO Pipelines' risk of delivery market loss.

Forecast industrial growth in the Fort McMurray, Edmonton and Fort Saskatchewan regions, largely as a result of oil sands developments and associated refining requirements, will contribute to future growth in throughput on ATCO Pipelines' system.

ATCO Pipelines signed an agreement in late 2004 to build a fifth interconnection with the Alliance Pipeline at Shell Creek which will connect ATCO Pipelines' Grande Cache transmission system to the Alliance Pipeline system. This project will require installation of a new compressor station in 2005.

ATCO Pipelines also signed agreements in 2004 to construct receipt meter stations and laterals in the Red Deer and Wetaskiwin areas to connect CBM production to the ATCO Pipelines transmission system. The high level of CBM development activity in these regions is forecast to accelerate in 2005. ATCO Pipelines will continue to pursue incremental receipt volumes associated with CBM development.

Custody transfer flow computers, required for customer load balancing, will be installed at 158 gate stations on the ATCO Pipelines' north system and 30 gate stations on the ATCO Pipelines' south system in 2005.

ATCO Pipelines continues to strongly support and be involved in environmental committees and initiatives through various industry associations including the Canadian Energy Pipeline Association (CEPA) and the Canadian Gas Association (CGA).

Utilities Group Operations

The Utilities Group remains committed to the communities we serve by operating regional offices and service centres throughout the province and through an active community involvement program. ATCO Gas built new service centres in Sherwood Park, Stony Plain and Hinton in 2004. A new service centre opened in Red Deer in March 2005.

Our commitment to operational excellence also includes two unique customer services: ATCO EnergySense and the ATCO Blue Flame Kitchen.

ATCO EnergySense is a well-established delivery agent for Natural Resources Canada's EnerGuide for Houses (EGH) energy audit program. The EnergySense experts also provide unbiased energy efficiency information and advice to Albertans.

In 2004, ATCO EnergySense performed 15,280 residential energy evaluations – nearly twice the number performed in 2003 and the highest of any other delivery agent in the country. They also completed 28 commercial evaluations. The EGH program is also making a positive impact on the environment. Approximately 3,030 customer homes were retrofitted in 2004 based on ATCO EnergySense recommendations, resulting in a reduction of 9,600 tonnes of greenhouse gas emissions.

The ATCO Blue Flame Kitchen had another record-breaking year for cookbook sales with more than 40,000 copies of Romancing the Flame and A Holiday Collection cookbooks sold. In addition to being a regular feature in newspapers, on radio and on a popular, weekly noon-hour television program, the Blue Flame Kitchen also responded to more than 41,600 telephone inquiries from customers seeking cooking and household advice. The Blue Flame Kitchen website now contains more than 1,000 searchable recipes and home economy tips.

The Oracle Financials System, an integrated computer-based program, was successfully implemented in October 2004 to replace the aging legacy financial information system. Oracle will provide Utilities Group companies with greater efficiencies in managing financial information and business processes.

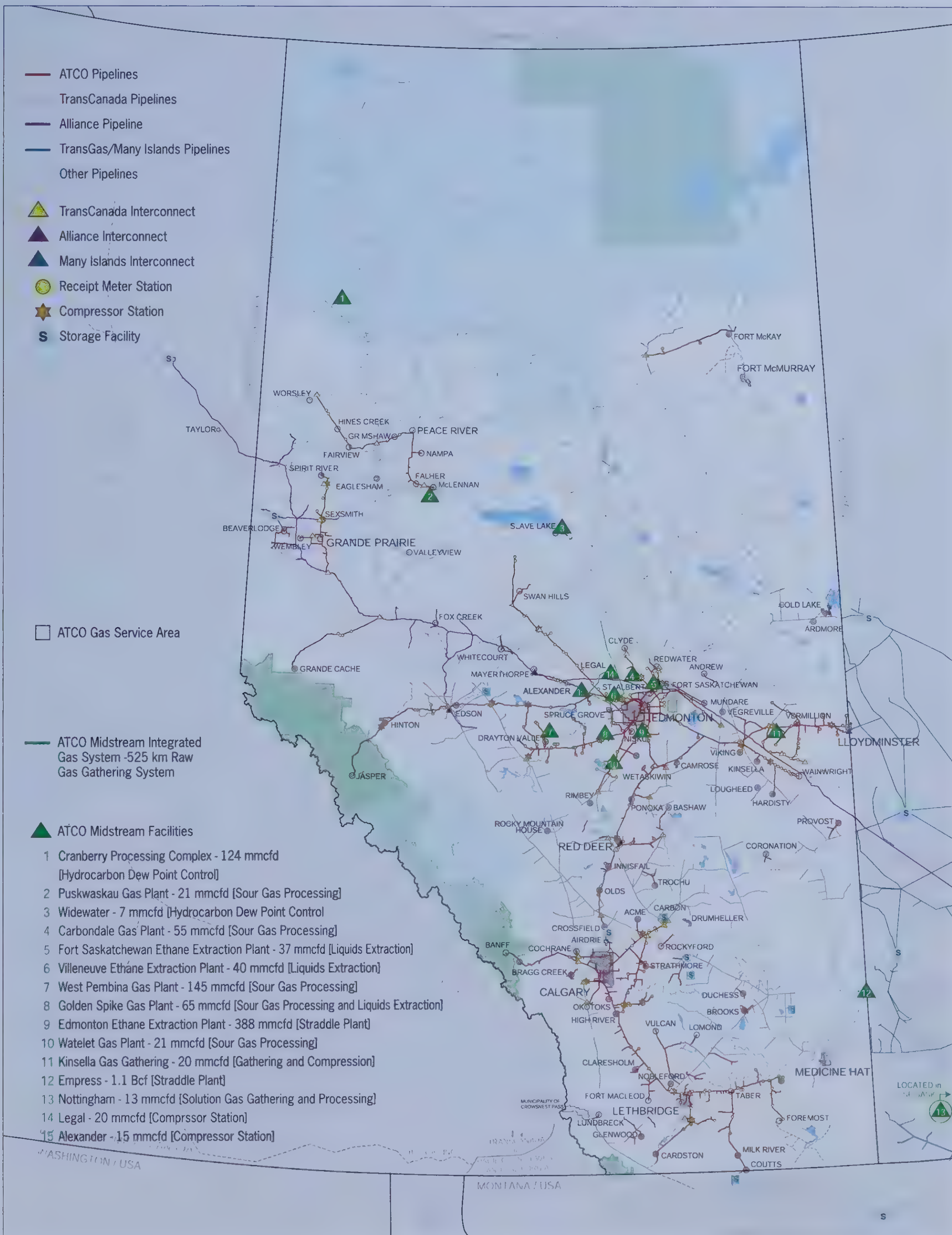
Moving forward, our utilities are well-positioned to focus on what they do best – safe, reliable delivery of natural gas, electricity and water.

S.W. Kiefer.

Siegfried W. Kiefer
Managing Director, Utilities

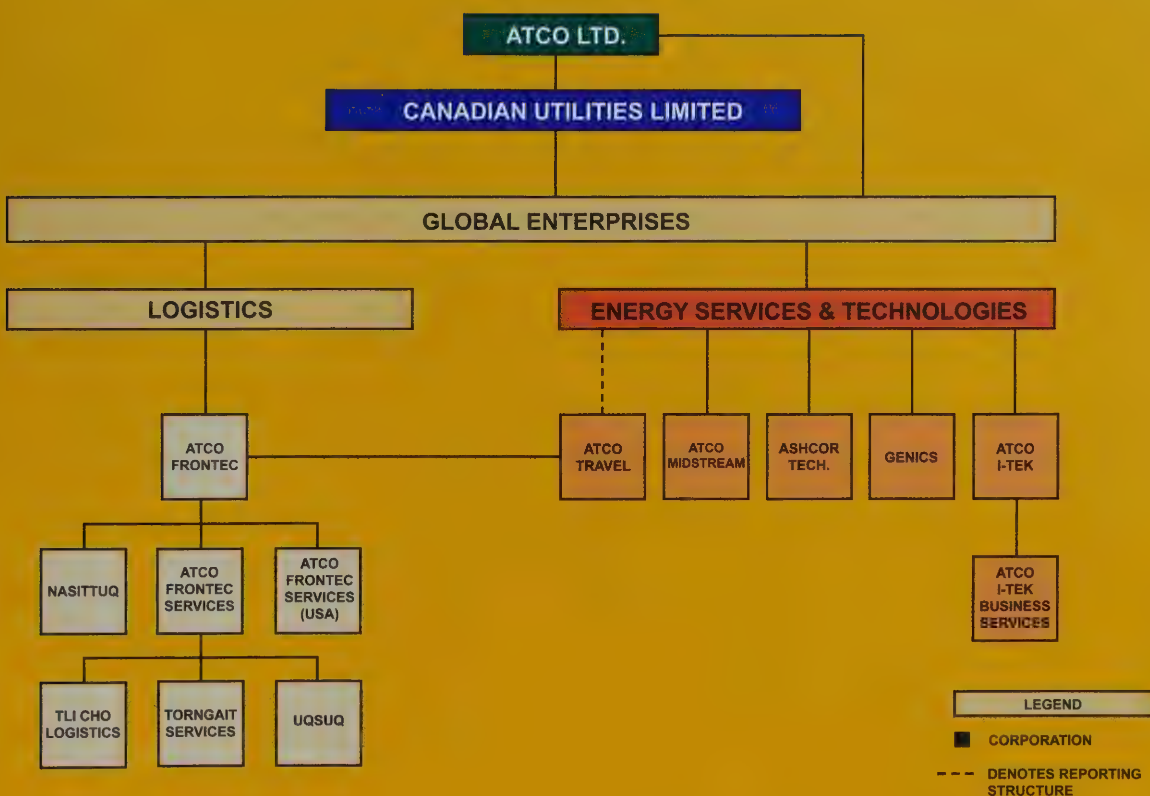
Electric Power System

Natural Gas System



The Companies in the Global Enterprises Group focus on technologies, logistics, facilities management and energy services.

Global Enterprises



◀ Photo: The Alaska Radar System is managed by ARCTEC Alaska, a joint venture created in 1994 between ATCO Frontec and Arctic Slope World Services. ARCTEC Alaska's contract, in place for up to ten years, is to operate and maintain 18 radar sites, ten of which are located above the Arctic Circle.

Canadian Utilities has established many partnerships with Aboriginal groups based on mutual trust and respect.

LOGISTICS

ATCO Frontec

Achieving high performance ratings, expanding and strengthening existing projects, winning new business ventures and earning service excellence recognition from customers, resulted in a year of solid growth for ATCO Frontec.

Following a redefining in business focus, the company commenced 2004 with a growth strategy centred on two core competencies: site support services and facilities management.

Successful implementation centres on quality relationships. The success of those relationships was evident in May when the United States Air Force awarded ARCTEC Alaska (a ten year-joint venture partnership between ATCO Frontec and Alaska native-owned Arctic Slope World Services Inc.) the contract renewal for the Alaska Radar System. Since 1994, ARCTEC Alaska has operated and maintained 18 short and long range radars, scattered over 590,000 square miles of Alaska. The system monitors more than two million square miles for the Alaska North American Aerospace Defence Command (NORAD) region. The new contract, in place for up to ten years, is for the continued operation and maintenance of the electronics and support systems and the Maintenance Control and Communications Centre at Elmendorf Air Force Base in Alaska. Since the start, ARCTEC Alaska has consistently achieved high ratings for all evaluated areas of performance.

Since the late 1980s ATCO Frontec has established a number of partnerships with aboriginal groups throughout the North. Each of these partnerships is based on mutual respect and trust and is designed to build capacity within aboriginal communities through the transfer of technical and managerial skills. Tli Cho Logistics, a jointly owned corporation of ATCO Frontec and the Dogrib Rae Band in Yellowknife, continued to deliver site support services to a number of facilities in the Northwest Territories including the Diavik diamond mine, the Tundra Mine and remediation of the Colomac Mine.

ATCO Frontec's Northern Operations group, based in Yellowknife, NWT, provides a wide range of services to northern businesses and government. In 2004 the group successfully re-bid airport ground handling contracts in Yellowknife and Iqaluit and building and facility maintenance services in Eureka, and successfully negotiated a new contract to provide site support services to the Resolute Bay Airport.

The Western Operations group, based in Edmonton, Alberta, provides a wide spectrum of security services for commercial, industrial and residential clients, property management services and airport services. The group had a very successful year earning new technical services and security service contracts as well as establishing a new office in Fort McMurray, Alberta.

Several initiatives in other domestic business units also met with success through the retention and expansion of responsibilities at the operations level.

Activity levels at the Voisey's Bay nickel project in Newfoundland Labrador (N.L.) accelerated during the year and Torngait Services Inc., (TSI) a joint venture between the Labrador Inuit Development Corporation and ATCO Frontec, provided permanent accommodation facilities for the project's mine and concentrator operation in Labrador. TSI sub-contracted ATCO Kent Inc., a joint venture between ATCO Structures and Kent Homes, to manufacture the 115,000

▲ Photo: Torngait Services Inc. (TSI) a joint venture between ATCO Frontec and the Labrador Inuit Development Corporation was awarded the contract to build the 115,000 square foot state-of-the art facility for 255 employees working at the Voisey's Bay site. The $23 million facility includes deluxe employee accommodation, kitchen and dining areas, recreation and lounge facilities as well as a gymnasium and squash court.

square foot permanent facility. During the peak construction period at the mine site, TSI had up to 200 employees working on both the permanent accommodation project and the site services contract, including transporting personnel and material, operating and maintaining facilities, building construction camps, off-loading ships, maintaining roads and grounds, removing snow, and erecting the permanent camp. Deadlines were met and, in some instances, exceeded by TSI in a thorough, timely, and safe manner. Final installation of the permanent accommodation facility is expected by the end of March, 2005.

As part of an overall commitment to the Labrador Inuit Association, TSI successfully completed a summer training program to coincide with the permanent accommodation project. Eleven candidates received orientation training at manufacturing sites located at Bouctouche, N.B., and Debert, N.S., followed by on-the-job training at Voisey's Bay. TSI also formally opened a branch office in Nain, N.L., to enhance coordination and liaison with the Labrador Inuit communities.

Other TSI achievements included the successful completion, in September, of an operating camp at Saglak, N.L., in support of a two-year PCB clean-up.

Internationally, ATCO Frontec's information systems technological support contract to the NATO Stabilization Force Organization (SFOR) based in Sarajevo and four remote locations in Bosnia and Croatia, completed a very successful first year of operation. This three year contract with two one-year extensions is achieving and exceeding requirements.

FUTURE OPPORTUNITIES

As part of the Global Enterprises Group of Companies, ATCO Frontec will take an active approach to site support services opportunities with ATCO Structures. Work continues on the positioning of Canadian Utilities' companies as participants in the gas pipeline projects unfolding in the North. ATCO Frontec's experience in delivering logistical and site support services in the North, combined with proven aboriginal training programs and long term aboriginal relationships, have significant value.

ATCO Midstream's Gas Gathering and Processing Group continued to maintain a high standard in 2004 by operating its gas plants with an availability of 99%.

ENERGY SERVICES & TECHNOLOGIES

ATCO Midstream

ATCO Midstream provides energy services in gas gathering and processing, storage and natural gas liquids extraction to a broad customer base. The Company focuses on building long term relationships by providing customers with cost-effective, timely, integrated solutions. ATCO Midstream has ownership interest in 15 natural gas processing and compression facilities with owned or operated gross licensed processing capacity of 2,060 million cubic feet per day. The Company also owns and operates approximately 1,000 kilometres of raw natural gas pipeline. Established in 1992, ATCO Midstream has proven to be a reliable partner in today's energy industry by combining our strengths of experienced staff and commitment to meet individual needs of our customers.

MIDSTREAM GROUP ACTIVITIES

ATCO Midstream's Gas Gathering and Processing (GG&P) Group continued to maintain a high standard in 2004 by operating its gas plants with an availability of 99%. In addition to increasing throughput at its Wolstitmor, Cranberry and Watelet facilities, the GG&P Group completed an extension of its gathering system in southeast Saskatchewan, which created another producing area to ensure a high level of throughput is maintained through ATCO Midstream's share of the Nottingham gas plant. The GG&P Group was also successful in 2004 in gaining full operatorship of the West Pembina gas plant, which significantly increased both the number of personnel within ATCO Midstream, as well as the total processing capacity for which ATCO Midstream is responsible. In 2005, the GG&P Group will focus on the infrastructure requirements of producers drilling for Coal Bed Methane, as well as greenfield or acquisition opportunities that complement our existing asset base.

Cost control, stronger natural gas liquids extraction margins, and increased facility throughput were the main drivers in the success of the Natural Gas Liquids (NGL) Group in 2004. The NGL Group is looking forward to pursuing the acquisition of existing NGL infrastructure in Alberta, as well as the development of new NGL facilities in producing regions with liquids-rich natural gas in 2005.

Storage and Energy Services' (S&ES) had a stronger year by providing customized services/products tailored to customers' needs. S&ES continues to balance regulatory, operations, credit and market volatility within ATCO Midstream's risk profile. In 2005, ATCO Midstream is evaluating suitable locations and reservoirs for a new commercial storage facility in Alberta.

GOING FORWARD

ATCO Midstream will continue to pursue growth opportunities in its core business areas but will also position itself for growth in new geographic areas such as the Far North, East and West coasts. The company will be expanding its expertise to pursue projects in the heavy oil and natural gas from coal industries.

ATCO Midstream is well positioned to provide gathering and processing services to the Coal Bed Methane producer industry, which is in its infancy in Alberta. With a diverse asset base, an experienced and enthusiastic staff and an extensive project lead list, ATCO Midstream has significant growth potential.

▲ Photo: The West Pembina Gas Plant is a large sour gas processing facility located west of Drayton Valley, Alberta. Operated by ATCO Midstream, the joint venture facility is licensed to process approximately 145 mmcfd of natural gas.

ATCO I-Tek

ATCO I-Tek delivers reliable large-scale customer care and technology solutions. In 2004 – a year of unprecedented change – the company's people, processes and technology proved they have the ability and agility to meet their clients' critical business needs.

ATCO I-Tek designed and implemented call centre and billing services for Direct Energy Marketing Limited (DEML), converted more than one million retail accounts, established new distribution-only services for ATCO Gas and ATCO Electric, and launched Oracle Financials, a complete financial solution for three ATCO companies.

At the same time, ATCO I-Tek maintained a diverse suite of fully-managed technologies; provided around-the-clock Information Technology (IT) support for more than 4,000 computers; and supported more than 700 desktop and 200 specialized business applications.

ATCO I-Tek also answered almost 2.6 million customer calls, produced more than 13.5 million utility bills and processed 11.3 million payments totaling $1.9 billion.

After signing a 10-year agreement with DEML, North America's largest energy retailer, ATCO I-Tek began providing retail customer care services for its first major external client on May 4, 2004.

To meet the requirements of Alberta's new utility model, ATCO I-Tek designed and built a new Customer Information System with retail capabilities, and re-configured the Distribution Customer Care Information System serving ATCO Gas and ATCO Electric. The world-class proprietary systems handle more than two million retail and distribution customer accounts – double what ATCO I-Tek managed before the transfer of ATCO Gas' and ATCO Electric's retail energy supply business to DEML.

ATCO I-Tek also provided retail and distribution training for more than 500 employees; created manual and automated controls to protect client data; customized hundreds of processes, policies, procedures and training resources; and expanded its call centre operations from three to five independent call centres.

In the months before and after the transition, ATCO I-Tek worked closely with DEML, ATCO Gas, and ATCO Electric to ensure a smooth, convenient conversion for customers. According to a customer satisfaction survey conducted just six months after the conversion, more than 86% of customers were satisfied or extremely satisfied with the quality of service they received when they called the regulated retail call centre.

ATCO I-Tek successfully implemented Oracle Financials for ATCO Electric, ATCO Gas and ATCO Pipelines. The largest system integration project in CU's history was delivered on time, on budget, and with no significant operational disruption.

The major undertaking involved adapting the financial software to meet the complex regulated business needs of the Utilities Group; converting 235,000 inventory items, projects, assets and general ledger codes; installing the software on more than 800 workstations and upgrading another 600 workstations. In the first six weeks using Oracle, the Utilities Group processed more than $130 million in payments and purchase orders.

Building on a year of unprecedented change and achievements, ATCO I-Tek is well positioned for future growth and success.

ATCO Travel

In 2004, ATCO Travel continued its leadership as a full service Travel Management Company for corporate clients, the general public, and the ATCO Group of Companies.

ATCO Travel maintained solid growth in new business opportunities, opening new offices in Fort McMurray, Alberta and Ottawa, Ontario, in addition to renewing its affiliation with TSI Travel (a joint venture between ATCO Frontec and Labrador Inuit Development Corporation) in St. Johns, Newfoundland.

ATCO Travel also increased the number of independent vacation agents who operate under ATCO Travel's banner by 70% in 2004, bringing additional revenue to the company as well as improving our negotiating power with large industry suppliers.

Corporate account growth targets for 2004 were reached towards the end of the year with a significant contract awarded to perform both commercial and charter aircraft management on behalf of a large oil and gas company. This contract allows ATCO Travel to perform an expanded role in terms of logistical management for air and ground coordination on behalf of the customer as opposed to just commercial airline bookings. This new account bodes well for ATCO Travel's continued account expansion in the same area, complementing the opening of a travel office in Fort McMurray.

Again in 2004, ATCO Travel was able to re-sign all major accounts to new agreements prior to the end of the year, ensuring continued demand from these accounts, and delivering high-end customer service throughout 2005.

In 2005, ATCO Travel will expand its four key service delivery models, Corporate Management, Vacation Services, Groups and Meeting Planning, and Air Charter programs.

Genics

Genics Inc. develops, manufactures and markets innovative environmentally safe wood preservation products for utility, commercial, and residential markets throughout North America. Genics serves many Canadian utility companies providing both inspection service and wood preservation treatment that extends wood pole asset life.

The utility adoption of Genics' environmentally responsible and user/public safety wood preservatives continued in North America with significant projects awarded in Alberta, in Missouri and Illinois, and throughout the United States. There has been some interest expressed in the Genics product lines

internationally and Genics will evaluate the challenges of getting preservative product labels into these jurisdictions.

Genics has also filed patents for liquid and solid wood preservatives that have attributes protecting engineered wood and lumber against attack by mold, decay, termites, and insects.

ASHCOR Technologies

ASHCOR Technologies had a very successful year in 2004 marketing coal combustion products from ATCO Power's coal-fired generating stations in Alberta. The predominant product marketed is fly ash, the non-combustible residue remaining after coal is consumed in a power plant furnace. It is designated a supplementary cementing material by the Canadian Standards Association. Its primary use is as a partial replacement for cement powder in concrete products and in oil well cements. Replacement of Portland Cement by fly ash, a by-product, reduces Green House Gas (GHG) emissions.

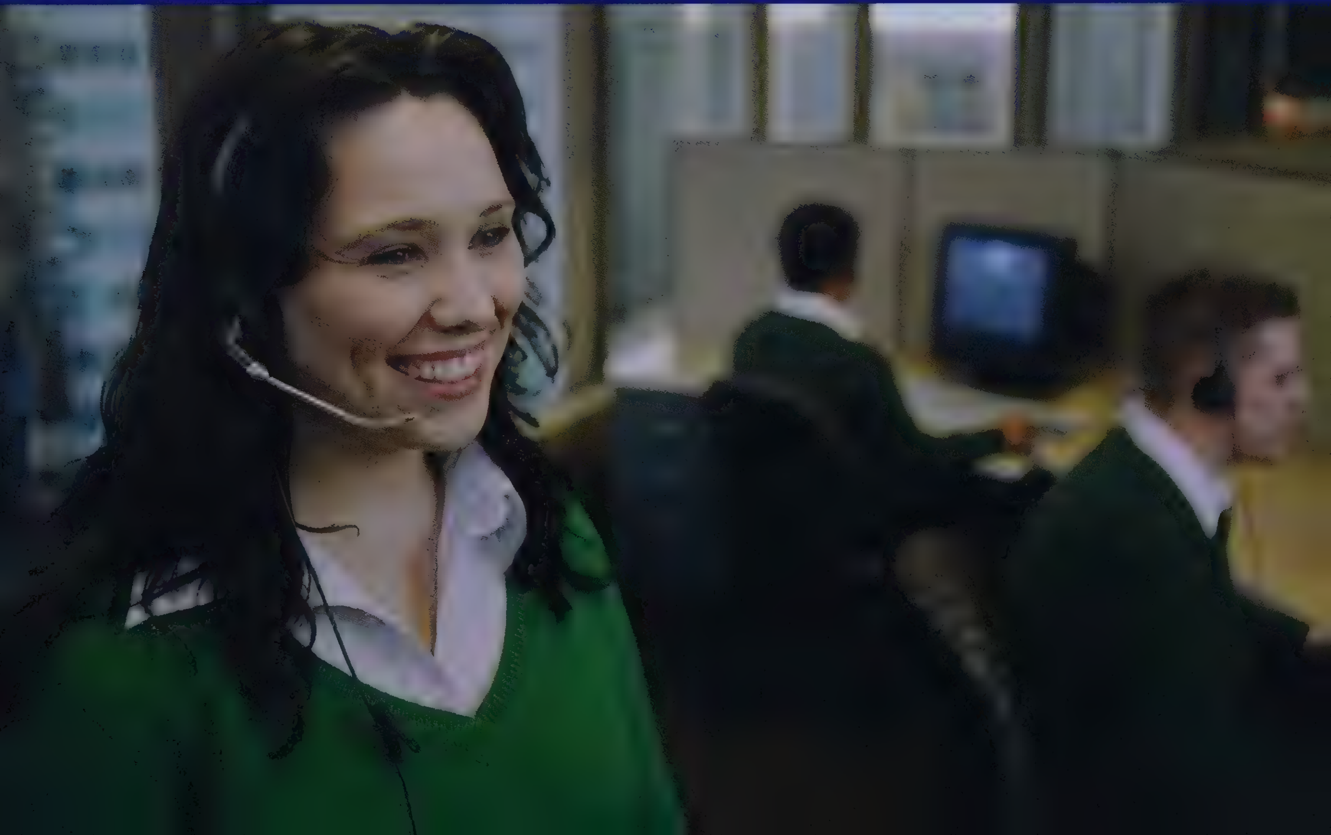
Since its inception in 1998, ASHCOR has established itself as a premier supplier to the construction and oilwell drilling markets in western Canada.

ASHCOR continues to pursue research and development of value-added products derived from coal combustion products.

Michael Shaw

Michael M. Shaw
Managing Director, Global Enterprises

▼ Photo: In 2004 ATCO I-Tek produced more than 13.5 million utility bills, processed 11.3 million payments and answered almost 2.6 million customer calls. Katherine Dallinger, is one of the many friendly and helpful customer care specialists who assist customers in ATCO I-Tek's five call centres.



Since 1998, ATCO Power and its partners have invested $1.1 billion and added 1,100 MW of electricity supply to the Alberta grid.

Power Generation

◀ Photo: ATCO Power owns and operates the 670 MW coal-fired Battle River Power Plant located in central Alberta near Forestburg.

The Power Generation Group combines the independent power plants built and operated by ATCO Power with the formerly regulated legacy plants in Alberta previously owned and operated by ATCO Electric.

POWER GENERATION GROUP

ATCO Power

The Power Generation Group has operations in Canada, the United Kingdom and Australia and is an acknowledged leader in developing, constructing and operating environmentally progressive natural gas fired plants. 2004 was a challenging year for the Power Generation Group as low power prices and drought in Alberta, the addition of five new operating plants and continued uncertainty in the United Kingdom (U.K.) related to the TXU bankruptcy counter-balanced some outstanding achievements in other areas.

■ ATCO Power - CANADA

ATCO Power is well positioned to maintain its rank as a leading Canadian-based independent power producer. At the end of 2004, the Power Generation Group operated a portfolio of 19 plants with a combined capacity of over 4,800 MW, and has a total ownership interest of 2,700 MW in these plants. ATCO Power has a wide portfolio of efficient generating assets, with the vast majority of electric and steam output sold under long-term contracts and financed with fully amortizing long-term non-recourse loans. Performance at the 19 power plants operated by the Power Generation Group was strong in 2004, reflecting a shift in focus from development to operational excellence as the new plants were brought to full operation.

The 580 MW natural gas-fired combined-cycle Brighton Beach generating plant in Windsor, Ontario was commissioned in July 2004. The start-up and commissioning of this plant was achieved on a very tight schedule - an outstanding achievement given the complex nature of this large power plant. ATCO Power and its partner, Ontario Power Generation Inc., sell all of the output from this plant under a long-term energy conversion agreement signed in November 2001 with Coral Energy.

2004 was the first full year of operation for four power plants commissioned in 2003. The 260 MW Cory Cogeneration Plant near Saskatoon supplies steam to the Potash Corporation of Saskatchewan and electricity to SaskPower Corp. This facility is 50% owned by ATCO Power and 50% by SaskPower International and operated efficiently throughout 2004.

The Scotford Cogeneration Plant and the Muskeg River Cogeneration Plant operated well throughout 2004. Scotford produces 170 MW and is owned 100% by ATCO Power, while the 170 MW Muskeg River plant is owned 70% by ATCO and 30% by SaskPower International. These plants supply steam and power, respectively, to the Scotford Upgrader located near Fort Saskatchewan and to the Muskeg River Mine, located near Fort McMurray. Electricity not sold on site is sold to the market through the Alberta Electricity System Operator.

The 32 MW Oldman River project, owned 100% by ATCO, produced energy throughout 2004. The Piikani Nation retains the option to purchase a 25% ownership interest in this plant.

The Power Industry in Alberta, which was deregulated in 2001, continued to function with excess supply in 2004 which created downward pressure on Power Pool Prices. The Power Generation Group has been working constructively with other industry participants and the government to address the structural issues in the Alberta Market to reduce volatility to the consumer while producing a fair return on investment for the generators. Since 1998, ATCO Power and its partners have invested $1.1 billion and added 1,100 MW of supply to the Alberta Grid.

The Power Generation Group's largest power plants in Alberta, both coal-fired and referred to as "Legacy Plants",

are the Battle River Generating Station and the Sheerness Generating Station. The Battle River facility, located near Forestburg and owned 100% by ATCO Power, generates 670 MW of electricity. The Sheerness plant, located near Hanna and owned 50% by ATCO Power, generates 760 MW of electricity. Following deregulation in 2001, the output from these two plants is sold under long term power purchase arrangements. Both plants are operated by ATCO Power and achieved high availability during 2004 despite difficult conditions caused by severe drought conditions.

ATCO Power - UNITED KINGDOM

ATCO Power's principal U.K. asset is the 1,000 MW gas-fired Barking Power combined-cycle plant located in east London. The company is the operator of the plant and has a 25.5% equity interest. ATCO Power continues to work to resolve the difficulties created in 2002 when one of the shareholders/offtakers of Barking Power Limited, TXU Europe, filed for bankruptcy. On January 28, 2005, TXU creditors approved the Company Voluntary Arrangements (CVA) which included Barking Power Limited's claim for compensation. The impact of the CVA will not be known until the first half of 2005.

The 100% owned Heathrow plant continued to achieve high levels of operational effectiveness in 2004.

ATCO Power - AUSTRALIA

ATCO Power's two plants in Australia, the 180 MW Osborne cogeneration plant near Adelaide, and the 33 MW Bulwer Island cogeneration plant in Brisbane, continued to perform well and met the requirements of the long-term power supply and steam agreements. Both plants are jointly owned with Origin Energy.

In all three jurisdictions, we have strong management and operations teams dedicated to enhancing our effectiveness and capturing new expansion opportunities in the future.

Gerry W. Welsh
President & Chief Operating Officer
Power Generation
(retired March 2005)

▼ Photo: The 580 MW Brighton Beach Power Plant located in Windsor, Ontario was commissioned in July 2004.

Environment Report

▲ Photo: One of ATCO Electric's innovative, environmentally-friendly solutions replaced traditional mechanical tree clearing in a sensitive area of Jasper National Park. Aseniwuche Development Corporation, ATCO Electric and Parks Canada used logging horses to thin about 5.7 hectares of forest.

Canadian Utilities (CU) in 2004 again showcased environmental stewardship both through "operational excellence" within its companies and the implementation of innovative programs to reduce emissions or enhance environmental protection.

Working hand-in-hand with the diverse communities it serves, CU ensures that environmental protection and enhancement are integral to our business processes. CU companies in 2004 participated in scores of initiatives, from grassroots toxic roundups and community cleanups to the development of progressive facilities and the funding of advanced technologies.

Of special note, ATCO Gas was nationally recognized at Canada's Climate Change Seventh Annual Leadership Awards for cutting Greenhouse Gas Emissions to almost 50% below 1990 levels.

ATCO Gas also received Honourable Mention in the Oil and Gas – Pipelines and Natural Gas Distribution category for successfully reducing emissions by 6,040 tonnes or 13.3 million pounds of carbon dioxide equivalent from 1990 levels.

■ NAIT HYDROGEN FUEL CELL PROGRAM

ATCO Gas participates in innovative projects to deliver energy more efficiently and to lower greenhouse gas emissions, including a $1.2 million commitment to a hydrogen fuel cell research project at the Northern Alberta Institute of Technology.

The project, the first commercial high-voltage fuel cell in Canada, now supplies 10% of the school's electricity requirements and heats the swimming pool and water for showers at its main Edmonton campus. The fuel-cell project also provides a unique learning opportunity for the next generation of engineers.

NATURAL GAS VEHICLES

In Banff National Park, Parks Canada continued to switch some of its vehicles to low-emission natural gas fuel, taking advantage of a new refueling station built by ATCO Gas in the town of Banff.

OKOTOKS SOLAR HEATING SYSTEM

ATCO Gas is participating in North America's first large-scale solar heating system in the town of Okotoks, Alberta. The system will collect thermal energy from 800 solar panels mounted on garage roofs of residential homes and transfer it to underground storage. The storage temperature increases during the summer so that during the winter season, the thermal energy is retrieved and distributed through a central heating system to homes in the community. ATCO Gas will manage the construction of the heating system and will operate and maintain it.

ATCO ENERGYSENSE

ATCO EnergySense carries out Natural Resources Canada's EnerGuide for Houses (EGH) energy audit program, and provides unbiased energy efficiency information and advice to Albertans. In 2004 ATCO EnergySense led all Canadian EnerGuide agents in rigorously undertaking more than 15,000 residential energy evaluations to help homeowners reduce energy consumption.

The total number of residential evaluations in 2004 was almost double the number of audits performed in 2003. Approximately 3,030 homes were renovated in 2004 based on ATCO EnergySense recommendations, resulting in an additional reduction of 9,600 tonnes of Greenhouse Gas Emissions. The number of major commercial evaluations also increased by 40%.

ATCO ELECTRIC SITE REMEDIATION PROGRAM

ATCO Electric marked in 2004 the second year of a three-year project to reduce its ecological footprint and to remediate 77 operating and decommissioned isolated generation plant sites. With 21 sites now restored to natural state, the massive reclamation project is now 70% complete. These sites will be available for future use as they are restored to the stringent standards required for residential or parkland use.

ATCO Electric's 350 km Dover-Whitefish transmission line in northern Alberta showcased exceptional environment stewardship. ATCO Electric built 70 new homes for wildlife from debris along the transmission line right-of-way. Piles of wood and branches were turned into furbearer shelters, erected to enhance wildlife habitat.

ATCO Electric was able to use knowledge gained from the project to develop new initiatives, including in Jasper National Park where innovative, environmentally-friendly solutions replaced traditional mechanical tree clearing. Aseniwuche Development Corporation, ATCO Electric and Parks Canada used logging horses to thin about 5.7 hectares of forest in an environmentally-sensitive area in Jasper National Park.

ATCO POWER

The opening of the 580-megawatt Brighton Beach Power Plant near Windsor, Ontario provides access to new electricity at 65% less Greenhouse Gas emissions when compared to conventional coal-fired generation. The state-of-the-art, natural gas fired plant also produces only traces of sulphur.

ATCO FRONTEC

Significant changes to existing health, safety and environment processes are underway. A newly created team of professionals has been established to update existing programs to stringent international standards and an internal committee has developed a leading edge information toolkit which has been distributed to all project supervisors.

Your Community

▲ Photo: ATCO Gas, the longest serving corporate sponsor at the Calgary Stampede, sponsors the Lost Kids program which tags children on the grounds. ATCO Structures provides the Lost Kids unit where children can stay and play in a safe atmosphere until their parents are found.

Canadian Utilities (CU) is firmly committed to improving the quality of life in communities around the world where our employees work and live. Each year, our companies support hundreds of community initiatives, both large and small, through financial contribution and volunteer effort.

Canadian Utilities respects and supports the important role local endeavours play in creating vibrant communities. CU believes in supporting a wide variety of programs that our thousands of employees care about.

Canadian Utilities focuses support in five core areas: arts and culture, community development, youth and education, sports and recreation, and health and welfare. Many of our initiatives bridge several areas creating even more lasting impact.

Additionally, opportunities are provided for employees to designate their personal charitable donations to specific health and welfare organizations with CU matching their contributions.

Canadian Utilities also provides incentives to employees who volunteer their time to enrich community life. In 2004, employees in the Utilities Group alone volunteered more than 36,000 hours in their communities.

From capital donations to hospitals and educational institutions across Alberta, to supporting leading development programs such as the Duke of Edinburgh Awards and the ATCO Tyrrell Learning Centre in Drumheller, CU demonstrates support that enriches communities.

SPORTS AND RECREATION

Several CU companies jointly sponsored and participated in the Arctic Winter Games in Fort McMurray. ATCO Plaza was the gathering place for thousands of athletes, judges, spectators, dignitaries and entertainment for the opening and closing ceremonies, nightly medal presentations, evening concerts and cultural events.

Canadian Utilities again supported the province-wide Alberta Games program as it has done since 1988. In 2004 our companies were at the Winter Games in Peace River, and at the Summer Games in Okotoks, High River and the MD of Foothills.

YOUTH AND EDUCATION

At the National Aboriginal Achievement Foundation's Aboriginal Youth Career Fair in Edmonton, ATCO Gas, ATCO Electric, ATCO Frontec, ATCO I-Tek and Northland Utilities Limited either sponsored booths or speakers as more than 1,800 Aboriginal youth from western Canada explored career options.

ATCO I-Tek donated 1,000 computers, 843 monitors and 96 printers to the Alberta Computers for Schools program in 2004, bringing to more than 6,000 the pieces of equipment given in the last three years.

ARTS AND CULTURE

At the Northern Alberta International Children's Festival in St. Albert, ATCO Gas was a Platinum Sponsor, delivering programs such the ATCO Gas Creative Spark Outdoor Stage and co-presenting the Optimist Blue Flame Pancake Breakfast. As it has done since 1996, CU also sponsored the Calgary International Children's Festival.

COMMUNITY DEVELOPMENT

Edmonton's Centennial Legacy Project – Sir Winston Churchill Square – was an important project for the City of Edmonton as it celebrated its 100th anniversary in October, 2004. ATCO Gas prominently supported the Sir Winston Churchill Square Redevelopment Legacy project.

The annual ATCO Gas Charity Golf Classic at the Edmonton Golf and Country Club raised $24,000 in support of Crime Stoppers Association of Edmonton and Northern Alberta programs and services. This is the seventh year ATCO Gas has hosted this tournament and the third year we've partnered with Crime Stoppers.

ATCO Gas and the Calgary Zoo opened a new habitat for North America's smallest and scarcest wild canine – the swift fox, whose fragile and endangered existence is now making a comeback in western Canada.

HEALTH AND WELFARE

ATCO Pipelines employees volunteered time by participating in Habitat for Humanity projects in Edmonton and Calgary as well as other community organizations such as the Calgary Drop-in Centre.

ATCO Midstream's employees have displayed an exceptional spirit of giving in the communities where the company operates – Edmonton, Medicine Hat and Calgary. Building on 2003, when the company was the recipient of the "Award of Excellence" given by the United Way, ATCO Midstream was the 2004 recipient of the United Way Platinum award of excellence for generous leadership.

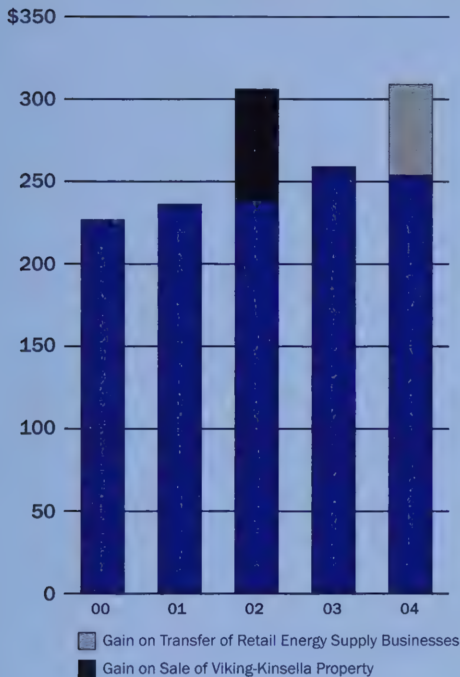
ATCO I-Tek's United Way employee campaign resulted in a 28% increase over the company's 2003 total contribution.

Through their employee charitable donation programs, ATCO Gas and ATCO Pipelines' Employee Community Service Fund (ECSF) and ATCO Electric's Employee Community Health and Welfare Organization (ECHO), and the companies matching dollars, ATCO Gas, ATCO Pipelines and ATCO Electric contributed more than $1,000,000 to charities across Alberta in 2004.

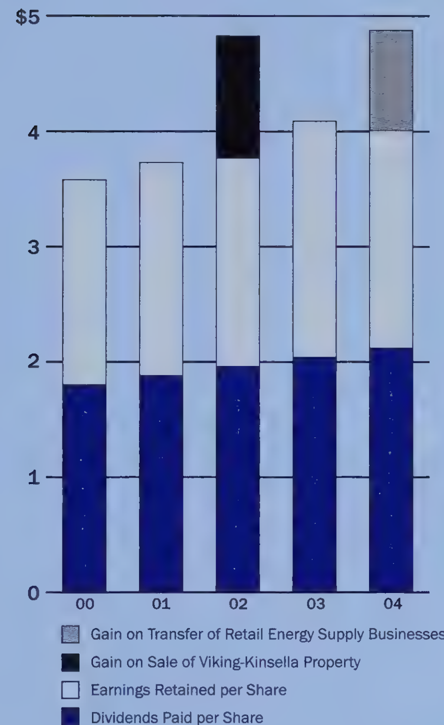
CANADIAN UTILITIES LIMITED FINANCIAL ACHIEVEMENTS IN 2004

- Earnings per share increased to $4.88 from $4.09 in 2003.
- Dividends paid per Class A and Class B share increased by $0.08 to $2.12 from $2.04 in 2003 – dividends have increased each year since 1972 – 32 years!
- Earnings increased by $49.9 million to $309.0 million compared to $259.1 million in 2003.
- Return on common equity was 15.2% compared to 13.7% in 2003.
- Total assets increased by $366 million to $6.5 billion compared to $6.1 billion in 2003.
- Long term debt increased by $366 million to $2.2 billion.
- Non-recourse long term debt decreased by $45 million to $761 million.
- Share owners' equity increased by $169 million to $2.1 billion compared to $1.9 billion in 2003.
- Cash flow from operations increased by $12.5 million to $538.3 million.
- Capital expenditures were $536 million in 2004 compared to $496 million in 2003. Over the previous five years, capital expenditures averaged $558 million per year.
- CU issued $480 million of debentures and $60 million of other debt in 2004. CU redeemed $100 million of debentures and $69 million of other debt in 2004.
- Non-recourse long term debt of $10 million was issued in 2004 for the Brighton Beach Power Project; CU redeemed $49 million of non-recourse long-term debt in 2004.

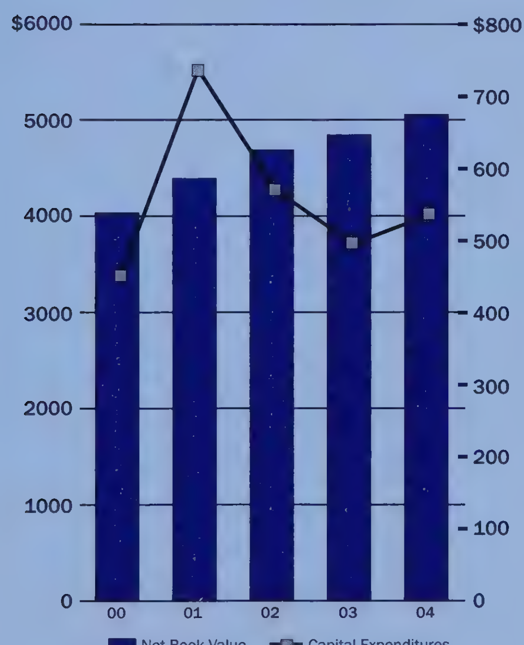
Earnings Attributable to Class A and Class B Shares
(Millions of Canadian Dollars)



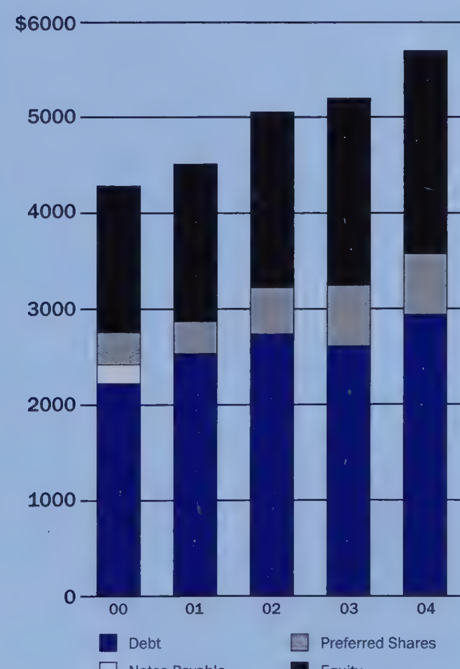
Earnings Per Class A and Class B Share
(Canadian Dollars)



Purchase of Property, Plant and Equipment
(Millions of Canadian Dollars)



Capitalization
(Millions of Canadian Dollars)



CONSOLIDATED FIVE YEAR FINANCIAL SUMMARY

(Millions of Canadian dollars, except as indicated)		2004	2003	2002	2001	2000
EARNINGS						
Revenues		**3,089.5**	3,742.6	2,975.9	3,513.6	2,924.5
Operating expenses (1)		**2,185.6**	2,868.7	2,169.8	2,695.4	2,087.0
Depreciation and amortization (1)		**291.5**	269.2	243.9	243.4	240.7
Interest		**203.7**	190.3	184.1	198.7	196.2
Dividends on preferred shares		**-**	-	-	-	0.6
Interest and other income		**(94.1)**	(33.4)	(136.2)	(41.4)	(23.5)
Income taxes (1)		**158.0**	155.6	190.0	164.2	179.9
Dividends on equity preferred shares		**35.8**	33.1	18.2	17.0	16.8
Earnings attributable to Class A and Class B shares (1)		**309.0**	259.1	306.1	236.3	226.8
SEGMENTED EARNINGS						
Utilities (2)		**168.7**	121.3	177.8	99.9	108.4
Power generation (1)		**80.0**	92.8	76.2	93.5	95.1
Global enterprises (1) (2)		**72.1**	56.1	45.5	34.8	22.7
Corporate and other/eliminations (1) (2)		**(11.8)**	(11.1)	6.6	8.1	0.6
Earnings attributable to Class A and Class B shares (1)		**309.0**	259.1	306.1	236.3	226.8
BALANCE SHEET						
Property, plant, and equipment		**5,045.3**	4,835.4	4,681.2	4,384.7	4,028.2
Total assets		**6,463.1**	6,096.5	5,958.6	5,425.2	5,424.7
Capitalization:						
Notes payable		**-**	-	-	4.6	197.1
Long term debt		**2,171.0**	1,805.3	1,916.9	1,855.9	1,865.5
Non-recourse long term debt		**760.9**	806.1	821.1	673.8	360.0
Equity preferred shares		**636.5**	636.5	486.5	336.5	336.5
Share owners' equity (1) (3)		**2,117.7**	1,948.5	1,827.0	1,639.5	1,523.0
Total capitalization (1)		**5,686.1**	5,196.4	5,051.5	4,510.3	4,282.1
CASH FLOWS						
Operations		**538.3**	525.8	504.6	532.2	490.2
Purchase of property, plant and equipment		**535.5**	495.7	569.8	735.3	451.3
Financing (excluding Class A and B dividends)		**333.8**	(10.6)	384.3	62.0	189.5
Class A and B dividends		**134.4**	129.3	124.2	119.0	114.0
CLASS A & B SHARES						
Shares outstanding at end of year (3) (thousands)		**63,392**	63,384	63,412	63,317	63,306
Return on equity (3)		**15.2%**	13.7%	17.7%	14.9%	15.4%
Earnings per share (3) ($)		**4.88**	4.09	4.83	3.73	3.58
Dividends paid per share (3) ($)		**2.12**	2.04	1.96	1.88	1.80
Equity per share (3) ($)		**33.41**	30.74	28.81	25.89	24.06
Stock market record - Class A non-voting shares ($)	High	**64.00**	59.60	60.10	56.05	51.45
	Low	**51.42**	45.10	48.80	44.50	31.00
	Close	**60.32**	57.86	51.21	49.75	51.00
Stock market record - Class B common shares ($)	High	**63.90**	58.75	60.50	54.20	51.15
	Low	**51.40**	45.50	49.00	44.95	31.10
	Close	**63.90**	58.00	52.65	49.00	50.55

(1) Figures for 2000-2003 have been restated for the retroactive changes in method of accounting for asset retirement obligations and stock options.
(2) Segmented earnings for 2000-2003 have been restated to reflect changes to the management reporting structure announced in August 2004.
(3) Includes Class A non-voting shares and Class B common shares.

(Millions of Canadian dollars, except as indicated)	**2004**	2003	2002	2001	2000
Utilities					
Natural gas operations					
Purchase of property, plant and equipment	**154.3**	141.0	103.1	84.6	87.6
Pipelines (thousands of kilometres)	**34.8**	34.2	33.7	33.5	33.5
Maximum daily demand (terajoules)	**2,049**	1,831	1,670	1,470	1,737
Natural gas sold (1) (petajoules)	**103**	198	201	187	209
Natural gas transported (1) (petajoules)	**120**	32	31	22	18
Total system throughput (petajoules)	**223**	230	232	209	227
Average annual use per residential customer (gigajoules)	**134**	134	136	131	148
Degree days - Edmonton (2)	**3,985**	4,245	4,274	3,661	4,210
- Calgary (3)	**3,978**	4,291	4,470	3,994	4,441
Customers at year-end (thousands)	**914.3**	887.8	862.0	837.7	816.1
Electric operations					
Purchase of property, plant and equipment	**223.4**	171.6	162.4	154.2	114.5
Power lines (thousands of kilometres)	**68.0**	67.0	67.1	64.2	58.6
Electricity distributed (millions of kilowatt hours)	**9,910**	9,768	10,224	10,108	10,392
Average annual use per residential customer (kWh)	**7,475**	7,261	7,445	7,270	7,444
Customers at year-end (thousands)	**206.2**	202.3	197.8	192.0	191.0
Pipeline operations					
Purchase of property, plant and equipment	**47.9**	33.6	47.3	77.4	63.5
Pipelines (thousands of kilometres)	**8.3**	8.3	8.3	8.2	7.9
Contract demand for pipelines system access (terajoules/day)	**4,606**	4,599	4,890	4,876	4,559
Power Generation					
Purchase of property, plant and equipment	**77.0**	131.7	236.0	384.2	155.5
Generating capacity (thousands of kilowatts)	**2,474**	2,397	2,036	2,036	668
Global Enterprises					
Purchase of property, plant and equipment	**14.5**	15.5	11.5	34.5	30.1
Natural gas processed (Mmcf/day)	**427**	399	420	429	366
Natural gas gathering lines (kilometres)	**1,000**	1,000	940	940	670

(1) Effective May 2004, with the transfer of the retail energy supply businesses, ATCO Gas' existing sales service customers became transportation service customers.
(2) Degree days - Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.
(3) Degree days - Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

Robert T. Booth (3)
Partner, Bennett Jones LLP
Calgary, Alberta

Mr. Booth is a partner in the law firm Bennett Jones LLP, based in Calgary, Alberta, and brings an extensive background in energy and natural resource law to the Canadian Utilities Limited Board. A member of the Law Society of Alberta and the Canadian Bar Association, Mr. Booth obtained a Bachelor of Engineering degree from the Royal Military College of Canada, Kingston, Ontario and an LLB from Dalhousie University, Halifax, Nova Scotia.

William L. Britton, Q.C. (1)
Partner, Bennett Jones LLP and Vice Chairman, Canadian Utilities Limited
Calgary, Alberta

Mr. Britton is a Partner at Bennett Jones LLP, Calgary, Alberta, and Vice Chairman of the Board for ATCO Ltd. and Canadian Utilities Limited. He was Chairman and/or Managing Partner of Bennett Jones during the period from 1981 to 1997. Mr. Britton was first elected to the Board of Directors of ATCO Ltd. in September 1975 and became a Director of Canadian Utilities Limited in June 1980. Mr. Britton is Chairman of the ATCO and CU Corporate Governance Committee (GOCOM). He is also a Director of Akita Drilling Ltd., Forest Oil Ltd., Denver Broncos Football Club, Hanzell Vineyards Ltd., Geary-Market Investment Company Ltd., The Yukon Electrical Company Limited, Barking Power Limited, Thames Power Limited, as well as numerous other organizations.

Brian P. Drummond (1) (4)
Corporate Director
Montreal, Quebec

Mr. Drummond is a Corporate Director based in Montreal, Quebec and most recently was Vice Chairman, Richardson Greenshields of Canada Limited. He was also previously President and Chairman of the Executive Committee of Greenshields Incorporated. Mr. Drummond is a Director and member of the Executive Committee of the McGill University Health Centre Foundation and is a Director of the Montreal General Hospital Foundation. Mr. Drummond is a past Chairman of the Investment Dealers Association of Canada and the Montreal Exchange. Mr. Drummond was first elected to the Board of ATCO Ltd. in 1968, when the company initially went public, and to the Board of Canadian Utilities Limited in 1997. Mr. Drummond is Chairman of the ATCO Ltd. Audit Committee.

Basil K. French (2) (3)
President, Karusel Management Ltd.
Calgary, Alberta

Mr. French is the President of Karusel Management Ltd., a Calgary based company specializing in management consulting and property management. Prior to the establishment of Karusel Management, Mr. French was with the firms of Buchanan, Barry, Miller and French Chartered Accountants and Price Waterhouse & Co. Mr. French is the Chairman of Canadian Utilities Audit Committee and is a Director of all ATCO and Canadian Utilities subsidiaries and the four ATCO Business Groups. Mr. French was elected to the Boards of ATCO Ltd. in November 1982 and Canadian Utilities Limited in April 1981.

Linda A. Heathcott (4)
Executive Vice President, Spruce Meadows
Calgary, Alberta

Mrs. Heathcott is Executive Vice President of Spruce Meadows. A former professional equestrian rider, Mrs. Heathcott was a member of the Canadian Equestrian Team for nine years and competed in the 1996 Olympic Summer Games in Atlanta, Georgia. On January 1, 2004, Mrs. Heathcott was elected Deputy Chairman of Akita Drilling Ltd. Mrs. Heathcott also serves on the Boards of Calgary Olympic Development Authority, Sentgraf Enterprises Ltd. and a number of ATCO Group subsidiary Boards. She was elected to the Board of Directors of Canadian Utilities Limited in May 2000.

Helmut M. Nelder (1) (2) (3) (4)
Corporate Director
Westerose, Alberta

Mr. Neldner is a Corporate Director based in Westerose, Alberta. He has extensive experience in the telecommunications industry and is the former President & Chief Executive Officer of AGT and Telus Corporation. He serves on the Boards of Directors of ATCO Ltd. and Canadian Utilities Limited, as well as the four ATCO Business Groups. He was nominated and elected to the Canadian Utilities Limited Board in May 1991 and the ATCO Ltd. Board in May 1997. Mr. Neldner is the Chairman of the ATCO and CU Risk Review Committees.

Michael R.P. Rayfield
Vice Chairman, Investment & Corporate Banking, BMO Nesbitt Burns
Toronto, Ontario

Michael Rayfield joined the Bank of Montreal in 1982, in New York, as Senior Vice-President, with responsibility for the Bank's corporate banking business in the United States, Latin America, Australia and Japan. In 1986 he was appointed Executive Vice-President, and is currently Vice Chairman, Investment and Corporate Banking. Prior to joining the Bank, he held senior executive positions with Barclays Bank in London, Chicago and New York.

Mr. Rayfield is a graduate of the Institute of Bankers, UK, the Senior Managers Program at Harvard University, Advanced Executive Program, J.L. Kellogg Graduate School of Management, Northwestern University and has studied at Cambridge University.

Mr. Rayfield is on the Boards of The Canadian Institute of International Affairs; The Toronto Symphony Orchestra's Governors Council, and the Board of Governors, Charter for Business, Duke of Edinburgh's Award Programme.

Larry R. Shaben
Chairman, Western New Ventures Capital Corporation
Edmonton, Alberta

Mr. Shaben is the Chairman of Western New Ventures Capital Corporation, based in Edmonton, Alberta, and previously was Vice Chairman, Petrovalve International Inc. In 1989, Mr. Shaben retired from active political life to resume his business activities in the private sector. During his time with the Alberta government, he held several ministerial portfolios including Minister of Economic Development & Trade, Minister of Housing, and Minister of Utilities and Telephones. Mr. Shaben was nominated and elected to the Board of Directors of Canadian Utilities Limited in May 1995.

James W. Simpson (2)
Corporate Director
Danville, California

Mr. Simpson, former President of Chevron Canada Resources, retired after a career with ChevronTexaco that spanned 30 years. Some of his key management assignments included General Manager Research Services at the laboratory in Los Angeles; General Manager of the Executive Staff in San Ramon, California; Managing Director of New Ventures in the International upstream company and Vice President for Middle East and North Africa in the Business Development group. He is former Chairman of the Canadian Association of Petroleum Producers and has been active in the United Way and the World Petroleum Congress. Mr. Simpson serves on the Board of Petro-Canada and was elected to the Board of Directors of Canadian Utilities Ltd. in May 2004.

Nancy C. Southern
President & Chief Executive Officer, Canadian Utilities Limited
Calgary, Alberta

Nancy Southern was appointed President & Chief Executive Officer, ATCO Ltd. and Canadian Utilities Limited, effective January 1, 2003. Previously she had been Co-Chairman & Chief Executive Officer since January 2000, Deputy Chief Executive Officer since May 1998 and Deputy Chairman since January 1996 of ATCO Group. She has been a Director of the Corporation since 1990. Ms. Southern has full responsibility for executing strategic direction and the on-going operations of the corporation, reporting to the Board of Directors. She is currently a Director of ATCO Ltd. and Canadian Utilities Limited and serves on the Boards of all the ATCO Group subsidiary companies. She is also a Director of the Bank of Montreal, Shell Canada Limited, Akita Drilling Ltd., and Sentgraf Enterprises Ltd.

Ronald D. Southern C.B.E., O.C., LL.D.
Chairman of the Board of Directors, Canadian Utilities Limited
Calgary, Alberta

Ron Southern is Chairman of the Board of ATCO Ltd., Canadian Utilities and all ATCO Group subsidiary companies. Together with his late father, S.D. Southern, Mr. Southern founded ATCO Group in 1947 and served as the company's President for 48 years. He is credited with transforming the company to what it is today – one of Canada's premier corporations with assets of $7.0 billion and employing more than 7,000 people. Mr. Southern also serves as Chairman of Akita Drilling Ltd. and Sentgraf Enterprises Ltd.

D. Logan Tait, F.R.I., F.C.A. (3) (4)
President, Tait Management Services Ltd.
Lethbridge, Alberta

Mr. Tait retired as a Partner of Meyers Norris Penny LLP, Chartered Accountants and Business Advisors in the Lethbridge, Alberta, office May 2004 and now acts as a Consultant to the company. He is also President of Tait Management Services, a consulting firm which provides accounting services and tax advice. He has been active in the Canadian and Alberta Real Estate Association and Junior Achievement of Southern Alberta, and was elected a Fellow of Chartered Accountants in 1986. He was elected to the Board of Canadian Western Natural Gas in 1980, and Canadian Utilities Limited in May 1992.

Gordon G. Tallman (2)
Corporate Director
Calgary, Alberta

Mr. Tallman, former Senior Vice President, Royal Bank, Prairies Region, recently retired after a career spanning 42 years. Some of his key management responsibilities with the Bank included Vice President, Global Energy Group, Vice President Commercial Banking & National Accounts, and Senior Vice President, Lending – Risk Management, Group Chief Auditor. He serves on the Boards of Big Rock Brewery, P.F.B. Corporation, Investment Saskatchewan Inc. and is Chairman of the Boards of C.V. Technologies, Inc. and Enbridge Income Fund. Mr. Tallman joined the Board of Canadian Utilities Limited in May 2003.

Charles W. Wilson (2) (3)
Corporate Director
Evergreen, Colorado

Mr. Wilson is former President, Chief Executive Officer and Director of Shell Canada Limited and former President and Director of Shell Investments Limited (Canada). Mr. Wilson graduated from the University of New Mexico with his Master of Science in Engineering and held several senior executive positions in Refining & Marketing, Chemical, Oil & Gas Production and Corporate Planning during his career at Shell. He was elected to the Board of Canadian Utilities Limited in May 2000 and ATCO Ltd. in May 2002. He also sits on the Board for the Power Generation and Energy Services & Technologies Business Groups. Mr. Wilson was elected to the Big Rock Brewery Board in 1999 and to the Akita Drilling Board and Talisman Energy Board in 2002.

(1) Member of the Corporate Governance (Nomination, Succession and Compensation Committee - GOCOM)
(2) Member of the Audit Committee
(3) Member of the Risk Review Committee
(4) Member of the Pension Fund

OFFICERS

Ronald D. Southern
Chairman of the Board

William L. Britton, Q.C.
Vice Chairman of the Board

Nancy C. Southern
President & Chief Executive Officer

Karen M. Watson
Senior Vice President &
Chief Financial Officer

Susan R. Werth
Senior Vice President &
Chief Administration Officer

Brian M. Andrews
Vice President

D. Terrence Davis
Vice President, Internal Audit

Ian D. Hargrave
Vice President, Project Development

Erhard M. Kiefer
Vice President, Human Resources

Siegfried W. Kiefer
Managing Director,
Utilities & Chief Information Officer

Charles S. McConnell
Treasurer

Michael M. Shaw
Managing Director, Global Enterprises

Pat Spruin
Corporate Secretary

Paul G. Wright
Vice President, Finance & Controller

MANAGING DIRECTORS AND PRESIDENTS OF PRINCIPAL OPERATING SUBSIDIARIES

Paul F. Blaha
President, Genics Inc.

Richard (Rick) J. Brouwer
President, ATCO Pipelines

Kevin J. Cumming
President, ATCO Midstream Ltd.

Jerome F. Engler
President, ATCO Gas

Siegfried W. Kiefer
Managing Director, Utilities

Roberta (Bobbi) L. Lambright
President, ATCO I-Tek Inc.

R.L. (Vaughan) Payne
President, ATCO Travel Ltd.

Sett F. Policicchio
President, ATCO Electric Ltd.

Joseph (Joe) J. Schnitzer
President, ASHCOR Technologies Ltd.

Michael M. Shaw
Managing Director, Global Enterprises

Richard (Dick) H. Walthall
President & Chief Operating Officer,
ATCO Power Ltd.
(effective March 2005)

Gerry W. Welsh
President & Chief Operating Officer,
ATCO Power Ltd.
(retired March 2005)

Harry G. Wilmot
President, ATCO Frontec Corp.

INCORPORATION

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING

The Annual Meeting of Share Owners will be held at 10:00 a.m., M.D.T. Thursday, May 5, 2005 at The Fairmont Hotel Macdonald, 10065 - 100 Street, Edmonton, Alberta.

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL

Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Class A Non-Voting and
Class B Common Shares and Second Preferred
(Series Q, R, S, W and X) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/
Calgary/Vancouver

TRUSTEE AND REGISTRAR

Debentures
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/
Calgary/Vancouver

STOCK EXCHANGE LISTINGS

Class A non-voting Symbol CU.NV
Class B common Symbol CU.X
Listing Toronto Stock Exchange

CUMULATIVE REDEEMABLE SECOND PREFERRED SHARES

5.90% Series Q CU.PR.T
5.30% Series R CU.PR.V
6.60% Series S CU.PR.D
5.80% Series W CU.PR.A
6.00% Series X CU.PR.B
Listing Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS

Annual Reports to Share Owners and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: **www.canadian-utilities.com**

SHAREHOLDER INQUIRIES

Dividend information and other inquiries concerning Shares should be directed to:

CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1

Telephone: 1-800-387-0825
e-mail: inquiries@cibcmellon.com
Website: **www.cibcmellon.com**

Printed in Canada

CANADIAN UTILITIES LIMITED
An ATCO Company

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www.canadian-utilities.com

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2004

Financial Information

CANADIAN UTILITIES LIMITED
An ATCO Company

Consolidated Financial Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations

For the Year Ended December 31, 2004

Table of Contents

CANADIAN UTILITIES LIMITED
FINANCIAL ACHIEVEMENT IN 2004

- Earnings per share increased to $4.88 from $4.09 in 2003.
- Dividends paid per Class A and Class B share increased by $0.08 to $2.12 from $2.04 in 2003 – dividends have increased each year since 1972 – 32 years!
- Earnings increased by $49.9 million to $309.0 million compared to $259.1 million in 2003.
- Return on common equity was 15.2% compared to 13.7% in 2003.
- Total assets increased by $366 million to $6.5 billion compared to $6.1 billion in 2003.
- Long term debt increased by $366 million to $2.2 billion.
- Non-recourse long term debt decreased by $45 million to $761 million.
- Share owners' equity increased by $169 million to $2.1 billion compared to $1.9 billion in 2003.
- Cash flow from operations increased by $12.5 million to $538.3 million.
- Capital expenditures were $536 million in 2004 compared to $496 million in 2003. Over the previous five years, capital expenditures averaged $558 million per year.
- CU issued $480 million of debentures and $60 million of other debt in 2004. CU redeemed $100 million of debentures and $69 million of other debt in 2004.
- Non-recourse long term debt of $10 million was issued in 2004 for the Brighton Beach Power Project; CU redeemed $49 million of non-recourse long-term debt in 2004.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established internal accounting control systems to meet its responsibility for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

K.M. Watson
Senior Vice President and Chief Financial Officer

P.G. Wright
Vice President, Finance and Controller

AUDITORS' REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2004 and 2003 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 11, 2005

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31 **2004**	Three Months Ended December 31 2003 (Restated, Notes 1, 12, 15)	Year Ended December 31 **2004**	Year Ended December 31 2003 (Restated, Notes 1, 12, 15)
		(Unaudited)	*(Unaudited)*		
Revenues	3	**$ 662.6**	$ 950.3	**$3,089.5**	$3,742.6
Costs and expenses					
Natural gas supply	3	**65.3**	368.6	**925.9**	1,519.8
Purchased power	3	**15.4**	46.8	**95.8**	209.8
Operation and maintenance		**235.2**	216.1	**872.3**	858.2
Selling and administrative		**43.5**	52.8	**158.2**	158.3
Depreciation and amortization		**81.2**	72.8	**291.5**	269.2
Interest	11	**52.9**	47.1	**203.7**	190.3
Franchise fees		**37.5**	30.5	**133.4**	122.6
		531.0	834.7	**2,680.8**	3,328.2
		131.6	115.6	**408.7**	414.4
Gain on transfer of retail energy supply businesses	3	**-**	-	**63.3**	-
Interest and other income	4	**10.4**	9.5	**30.8**	33.4
Earnings before income taxes		**142.0**	125.1	**502.8**	447.8
Income taxes	5	**42.8**	29.7	**158.0**	155.6
		99.2	95.4	**344.8**	292.2
Dividends on equity preferred shares		**8.9**	8.9	**35.8**	33.1
Earnings attributable to Class A and Class B shares	3	**90.3**	86.5	**309.0**	259.1
Retained earnings at beginning of period as restated	6	**1,548.3**	1,382.1	**1,435.4**	1,311.7
		1,638.6	1,468.6	**1,744.4**	1,570.8
Dividends on Class A and Class B shares		**33.6**	32.3	**134.4**	129.3
Direct charges	7	**1.6**	0.9	**6.6**	6.1
Retained earnings at end of period		**$1,603.4**	$1,435.4	**$1,603.4**	$1,435.4
Earnings per Class A and Class B share	14	**$ 1.43**	$ 1.37	**$ 4.88**	$ 4.09
Diluted earnings per Class A and Class B share	14	**$ 1.42**	$ 1.36	**$ 4.86**	$ 4.07
Dividends paid per Class A and Class B share		**$ 0.53**	$ 0.51	**$ 2.12**	$ 2.04

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

	Note	December 31 2004	2003 (Restated, Notes 1, 12, 15)
ASSETS			
Current assets			
Cash and short term investments	17	**$ 699.5**	$ 328.1
Accounts receivable		**372.8**	540.6
Inventories		**172.9**	171.3
Income taxes recoverable		**-**	10.2
Future income taxes	5	**0.3**	-
Deferred natural gas costs		**-**	27.2
Prepaid expenses		**24.5**	25.6
		1,270.0	1,103.0
Property, plant and equipment	8	**5,045.3**	4,835.4
Security deposits for debt		**23.1**	23.1
Other assets	9	**124.7**	135.0
		$6,463.1	$6,096.5
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	10	**$ 1.2**	$ -
Accounts payable and accrued liabilities		**284.3**	478.8
Income taxes payable		**42.6**	-
Future income taxes	5	**-**	11.5
Deferred natural gas cost recoveries		**0.9**	-
Deferred electricity cost recoveries		**11.7**	1.0
Long term debt due within one year	11	**5.3**	-
Non-recourse long term debt due within one year	11	**50.6**	46.3
		396.6	537.6
Future income taxes	5	**222.4**	227.4
Deferred credits	12	**158.0**	135.1
Long term debt	11	**2,171.0**	1,805.3
Non-recourse long term debt	11	**760.9**	806.1
Equity preferred shares	13	**636.5**	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	14	**514.3**	510.5
Contributed surplus	1, 15	**0.4**	0.3
Retained earnings		**1,603.4**	1,435.4
Foreign currency translation adjustment		**(0.4)**	2.3
		2,117.7	1,948.5
		$6,463.1	$6,096.5

N.C. Southern

N.C. SOUTHERN
DIRECTOR

B.K. French

B.K. FRENCH
DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2004	Three Months Ended December 31 2003 (Restated, Notes 1, 12, 15)	Year Ended December 31 2004	Year Ended December 31 2003 (Restated, Notes 1, 12, 15)
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 90.3**	$ 86.5	**$ 309.0**	$ 259.1
Adjustments for:					
Depreciation and amortization		**81.2**	72.8	**291.5**	269.2
Future income taxes		**(16.0)**	(6.3)	**(18.5)**	(0.4)
Gain on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**(55.1)**	-
Deferred availability incentives		**8.1**	(1.5)	**2.8**	(1.7)
Other		**0.8**	1.8	**8.6**	(0.4)
Cash flow from operations		**164.4**	153.3	**538.3**	525.8
Changes in non-cash working capital	16	**(31.0)**	(82.8)	**102.3**	(52.8)
		133.4	70.5	**640.6**	473.0
Investing activities					
Purchase of property, plant and equipment		**(149.1)**	(176.7)	**(535.5)**	(495.7)
Proceeds on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**22.5**	-
Proceeds (costs) on disposal of property, plant and equipment		**(0.7)**	11.3	**(2.6)**	23.8
Contributions by utility customers for extensions to plant		**10.3**	13.8	**50.9**	48.1
Non-current deferred electricity costs		**4.0**	10.3	**(5.9)**	19.1
Changes in non-cash working capital	16	**8.3**	15.3	**3.4**	(30.0)
Other		**2.0**	1.0	**(2.1)**	0.7
		(125.2)	(125.0)	**(469.3)**	(434.0)
Financing activities					
Change in notes payable		**(96.0)**	(42.0)	**-**	-
Deferred electricity cost obligation		**-**	-	**-**	(51.0)
Issue of long term debt		**300.0**	12.0	**539.8**	25.5
Issue of non-recourse long term debt		**-**	-	**10.0**	40.7
Repayment of long term debt		**(36.8)**	(66.8)	**(168.6)**	(139.1)
Repayment of non-recourse long term debt		**(8.8)**	(5.5)	**(49.2)**	(38.0)
Issue of equity preferred shares		**-**	-	**-**	150.0
Issue (purchase) of Class A shares		**0.2**	0.1	**(3.0)**	(2.4)
Dividends paid to Class A and Class B share owners		**(33.6)**	(32.3)	**(134.4)**	(129.3)
Income tax reassessment	5	**12.9**	-	**12.9**	-
Changes in non-cash working capital	16	**(1.9)**	1.7	**(1.8)**	7.9
Other		**(5.3)**	(2.4)	**(6.3)**	(4.2)
		130.7	(135.2)	**199.4**	(139.9)
Foreign currency translation		**(0.1)**	0.6	**(0.5)**	(4.9)
Cash position [(1)]					
Increase (decrease)		**138.8**	(189.1)	**370.2**	(105.8)
Beginning of period		**559.5**	517.2	**328.1**	433.9
End of period		**$ 698.3**	$ 328.1	**$ 698.3**	$ 328.1

[(1)] Cash position includes cash and short term investments less current bank indebtedness.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2004

(tabular amounts in millions of Canadian dollars)

1. Summary of significant accounting policies

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments (the "Corporation"). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power (2000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants.

Effective January 1, 2004, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations that define the primary sources of GAAP. Adoption of these recommendations had no effect on earnings for the three months and year ended December 31, 2004.

Certain comparative figures have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations".

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the Alberta Energy and Utilities Board ("AEUB"), which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination.

The generating plants of Alberta Power (2000) were regulated by the AEUB until December 31, 2000 but are now governed by legislatively mandated Power Purchase Arrangements ("PPA") that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and December 31, 2020.

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (see Note 3). The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004 will be reduced accordingly for 2004 and thereafter. ATCO Pipelines, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical did not participate in this transfer and continue to purchase natural gas and electricity for sale to customers. In addition, the AEUB issued a decision that directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ends on March 31, 2005. Accordingly, ATCO Gas has entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes (see Note 20).

Accounting for regulated operations is described in Note 2.

1. **Summary of significant accounting policies** (continued)

Use of Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Prior to the transfer of retail energy supply businesses (see Note 3), revenues from regulated sales of natural gas and electricity by ATCO Gas and ATCO Electric were recognized upon delivery, primarily on the basis of meter readings, and included an estimate of usage not yet billed.

Revenues from ATCO Gas' regulated distribution of natural gas include variable charges, which are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues from the sale of natural gas by ATCO Gas from storage are recognized upon delivery.

Revenues from ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of electricity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transportation of natural gas are recognized on the basis of contractual arrangements.

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. PPA incentives and penalties are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues from the supply of contracted services are recorded by the percentage of completion method. Full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

1. Summary of significant accounting policies (continued)

Natural Gas Supply

Natural gas supply expense includes purchases of natural gas for regulated operations (see Note 3 regarding the transfer of retail energy supply businesses) and other subsidiaries. Natural gas supply expense for other subsidiaries consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties.

Prior to the transfer of retail energy supply businesses (see Note 3), natural gas supply expense for the regulated operations was based on the forecast cost of natural gas included in customer rates. Variances from forecast costs were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers and revenues and natural gas supply expense were adjusted accordingly.

Subsequent to the transfer of retail energy supply businesses, natural gas supply expense for the regulated operations is based on actual costs incurred.

Purchased Power

Prior to the transfer of retail energy supply businesses (see Note 3), purchased power expense in ATCO Electric was based on the actual cost of electricity purchased, whereas the amount included in customer rates was based on forecast cost. Revenues were adjusted for variances from forecast cost, and the variances were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers.

Purchased power expense in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Income Taxes

The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

1. Summary of significant accounting policies (continued)

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AEUB and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. This change in accounting had no effect on earnings for the three months and year ended December 31, 2004.

Deferred Financing Charges

Issue costs of long term debt are amortized over the weighted average life of the debt, issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption.

Deferred Availability Incentives

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Asset Retirement Obligations

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for asset retirement obligations as described in Note 12. The CICA recommendations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. The prior year's financial statements have been restated for the change in the method of accounting for asset retirement obligations.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

1. Summary of significant accounting policies (continued)

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

1. Summary of significant accounting policies (continued)

Pursuant to an AEUB decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in other assets.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for stock based compensation as described in Note 15. These recommendations require the expensing of stock options granted on and after January 1, 2002. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital. No compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by the recommendations. The prior year's financial statements have been restated for the change in the method of accounting for stock options.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment in share owners' equity.

Transactions denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of integrated foreign operations are recognized in earnings.

2. Accounting for regulated operations

While CICA recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the regulator renders a subsequent decision. The Corporation anticipates that there would be no material differences between the amounts approved by the regulator for collection or refund and the amounts included in assets or liabilities on the balance sheet.

The Corporation has chosen to retain the following existing accounting policies, as permitted by CICA recommendations that define the primary sources of GAAP, pertaining to regulatory decisions that give rise to deferred assets or liabilities:

2. Accounting for regulated operations (continued)

a) *Purchased power* – Purchased power expense for the regulated operations in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

b) *Future removal and site restoration costs* – Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, include a provision for future removal costs and site restoration costs (see Note 1 regarding the accounting policy for asset retirement obligations). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

c) *Employee future benefits* – Costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), are recognized in earnings when paid rather than accrued. The differences between the amounts accrued on an actuarial basis and paid are deferred in other assets.

d) Certain costs as required or permitted by the AEUB are deferred for recovery through future rates.

Similar accounting policies that pertained to the retail energy supply businesses that were transferred as of May 4, 2004 (see Note 3) included:

a) *Natural gas supply* – Natural gas supply expense was based on the forecast cost of natural gas included in customer rates. Variances from forecast costs were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers and revenues and natural gas supply expense was adjusted accordingly.

b) *Purchased power* – Purchased power expense in ATCO Electric was based on the actual cost of electricity purchased, whereas the amount included in customer rates was based on forecast cost. Revenues were adjusted for variances from forecast cost, and the variances were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers.

3. Transfer of retail energy supply businesses

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. Proceeds of the transfer were $90 million, of which $45 million was paid at closing, with the remainder to be paid 12 months following closing. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of $63.3 million before income taxes of $8.2 million. This transfer increased 2004 earnings by $55.1 million.

The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004 will be reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There will be no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions ("the transferred functions").

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm, commercial and small industrial customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

3. Transfer of retail energy supply businesses (continued)

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the agreements will terminate and the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below $200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

DEML has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek Business Services to provide billing and call centre services to ensure continued quality customer service. DEML has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

4. Interest and other income

	2004	2003
Interest	**$22.0**	$24.3
Allowance for funds used by regulated operations	**6.2**	4.4
Other	**2.6**	4.7
	$30.8	$33.4

5. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2004		2003	
Earnings before income taxes	**$502.8**	%	$447.8	%
Income taxes, at statutory rates	**$205.5**	**40.9**	$186.9	41.7
Federal general tax reduction [1]	**(18.4)**	**(3.7)**	(10.9)	(2.4)
Manufacturing and processing tax credit	**(7.7)**	**(1.6)**	(8.1)	(1.8)
Resource allowance	**(3.3)**	**(0.7)**	(3.5)	(0.8)
Crown royalties and other non-deductible Crown payments	**0.7**	**0.1**	1.1	0.3
Large Corporations Tax	**7.8**	**1.6**	8.1	1.8
Foreign tax rate variance	**(4.6)**	**(0.9)**	(2.6)	(0.6)
Non-deductible interest on foreign financing	**1.8**	**0.4**	1.5	0.3
Change in future income taxes resulting from reduction in tax rates	**(2.6)**	**(0.5)**	(2.1)	(0.5)
Unrecorded future income taxes relating to regulated operations	**4.4**	**0.9**	7.1	1.6
Natural gas and other property disposals	**-**	**-**	(0.6)	(0.1)
Transfer of retail energy supply businesses	**(12.1)**	**(2.4)**	-	-
Reduction in future income taxes resulting from a change in tax legislation in Australia	**-**	**-**	(8.9)	(2.0)
Change in method of accounting for future income taxes in certain regulated operations	**(15.8)**	**(3.1)**	(6.8)	(1.5)
Other	**2.3**	**0.4**	(5.6)	(1.2)
	158.0	**31.4**	155.6	34.8
Current income taxes	**187.6**		158.6	
Future income taxes (recoveries)	**$ (29.6)**		$ (3.0)	

[1] The federal general tax reduction of 7% (2003 — 5%) is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. An additional federal tax reduction of 2% (2003 – 1%) is applicable to earnings that have benefited from the resource allowance.

The future income tax liabilities (assets) comprise the following:

	2004	2003
Property, plant and equipment	**$216.7**	$216.8
Deferred assets and liabilities	**5.5**	35.7
Tax loss carryforwards	**(0.9)**	(1.2)
Income tax reassessment	**-**	(12.9)
Other	**0.8**	0.5
	222.1	238.9
Less: Amounts included in current future income taxes	**(0.3)**	11.5
	$222.4	$227.4

Unrecorded future income tax liabilities of the regulated operations amounted to $165.3 million at December 31, 2004. This balance includes $38.8 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

Expected future recoveries relating to tax loss carryforwards have been recorded in the amount of $0.9 million, of which $0.1 million begins to expire in 2007 and $0.8 million does not expire. In addition, there are tax loss carryforwards of $1.2 million for which no tax benefit has been recorded. These losses begin to expire in 2006.

Income taxes paid amounted to $134.5 million (2003 — $147.2 million).

5. Income taxes (continued)

In 2001, the Corporation received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. The Corporation did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities.

During 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. The Federal Government appealed the Tax Court's decision to the Federal Court of Appeal, which issued a decision on June 18, 2004 in favor of the Corporation. The Federal Government did not appeal the Federal Court of Appeal's decision to the Supreme Court of Canada. The Corporation has received a refund of $15.1 million, including interest, and has reversed the future income tax reduction of $12.9 million.

6. Retained earnings at beginning of period as restated

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
	(Unaudited)			
Retained earnings at beginning of period as previously reported	**$1,548.3**	$1,385.3	**$1,438.8**	$1,314.9
Adjustment to retained earnings for prior years' effect of change in method of accounting for asset retirement obligations (after income taxes)	**-**	(3.0)	**(3.1)**	(3.1)
Adjustment to retained earnings for prior years' effect of change in method of accounting for stock options	**-**	(0.2)	**(0.3)**	(0.1)
Retained earnings at beginning of period as restated	**$1,548.3**	$1,382.1	**$1,435.4**	$1,311.7

7. Direct charges to retained earnings

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
	(Unaudited)			
Purchase of Class A shares	**$1.6**	$0.9	**$6.6**	$3.4
Issue costs of equity preferred shares (after income taxes of $1.3 million)	**-**	-	**-**	2.7
	$1.6	$0.9	**$6.6**	$6.1

8. Property, plant and equipment

		2004		2003	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.6%	**$5,593.1**	**$2,082.1**	$5,191.9	$1,927.2
Power Generation	3.4%	**2,770.5**	**849.6**	2,703.2	768.7
Global Enterprises	8.2%	**260.5**	**123.5**	249.3	105.6
Other	4.8%	**27.0**	**4.7**	11.4	4.3
		$8,651.1	**3,059.9**	$8,155.8	2,805.8
Property, plant and equipment less accumulated depreciation			**5,591.2**		5,350.0
Unamortized contributions by utility customers for extensions to plant			**545.9**		514.6
			$5,045.3		$4,835.4

8. Property, plant and equipment (continued)

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $297.9 million (2003 — $285.7 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $75.7 million (2003 — $265.8 million) and non-depreciable assets of $40.4 million (2003 — $39.3 million).

9. Other assets

	2004	2003
Net accrued pension asset (Note 19)	**$ 55.9**	$ 52.5
Costs deferred for recovery through future regulated rates (1)	**25.0**	25.7
Deferred costs related to the transfer of retail energy supply businesses	**-**	10.8
Deferred financing charges (2)	**27.6**	27.9
Other (1)	**16.2**	18.1
	$124.7	$135.0

(1) Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to $12.2 million in 2004 (2003 – $5.2 million).

(2) Amortization of deferred financing charges, which was recorded in interest expense, amounted to $3.1 million in 2004 (2003 – $2.5 million).

10. Bank indebtedness and credit lines

At December 31, 2004, bank indebtedness consists of $1.2 million (2003 — nil), all of which has been borrowed under joint venture operating credit facilities, at an interest rate of 5.4%, secured by a general assignment of accounts receivable, inventories and property, plant and equipment of a foreign subsidiary corporation.

At December 31, 2004, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

		2004			2003	
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$ 326.0**	**$12.0**	**$314.0**	$ 350.0	$16.2	$ 333.8
Short term committed	**614.1**	**22.3**	**591.8**	624.3	49.8	574.5
Uncommitted	**69.0**	**11.4**	**57.6**	178.5	14.1	164.4
	$1,009.1	**$45.7**	**$963.4**	$1,152.8	$80.1	$1,072.7

Of the $45.7 million used at December 31, 2004, $16.8 million is included in long term debt and $28.9 million represents outstanding letters of credit.

11. Long term debt and non-recourse long term debt

Long term debt

	2004	2003
CU Inc. debentures – unsecured		
1994 Series 8.73% due June 2004	$ -	$ 100.0
1995 Series 8.43% due June 2005	125.0	125.0
2001 4.84% due November 2006	175.0	175.0
2002 4.801% due November 2007	50.0	50.0
2000 6.97% due June 2008	100.0	100.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
2000 7.05% due June 2011	100.0	100.0
2004 5.096% due November 2014	100.0	-
2002 6.145% due November 2017	150.0	150.0
2004 5.432% due January 2019	180.0	-
1999 Series 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
2004 5.896% due November 2034	200.0	-
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	100.0	100.0
	2,155.0	1,775.0
ATCO Power Australia Pty Ltd. credit facility, at Bank Bill rates, due July 2005, payable in Australian dollars, unsecured (1)	5.3	13.8
ATCO Power Canada Ltd. credit facility, at BA rates, due March 2007, secured by a pledge of cash (1)	11.5	12.0
Other long term obligation, at 4.25%, due June 2006, unsecured	4.5	4.5
	2,176.3	1,805.3
Less: Amounts due within one year	5.3	-
	$2,171.0	$1,805.3

Non-recourse long term debt

	2004	2003
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	$ 72.2	$ 80.8
At LIBOR, due to 2010 (1)	118.4	132.5
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 (1)	2.3	0.1
At 7.3325%, due to 2013 (1)	42.6	51.6
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.54% to 2008, at LIBOR thereafter, due to 2016 (1)	5.1	6.4
At 7.317% to 2008, at LIBOR thereafter, due to 2016 (1)	8.1	9.0
At 7.50% to 2011, at LIBOR thereafter, due to 2016 (1)	89.7	93.1
Joffre project financing:		
At 6.435% to 2004, at BA rates thereafter, due to 2012 (1)	-	2.3
At 7.286%, due to 2012 (1)	31.9	33.4
At 8.59%, due to 2020	32.0	32.0

11. Long term debt and non-recourse long term debt (continued)

Non-recourse long term debt (continued)

	2004	2003
Scotford project financing:		
At 5.202%, due to 2008, at BA rates thereafter, due to 2014 (1)	**50.4**	53.7
At 5.202%, due to 2008, at LIBOR thereafter, due to 2014 (1)	**12.6**	13.9
At 7.93%, due to 2022	**27.6**	28.2
Muskeg River project financing:		
At 5.247%, due 2007, at BA rates thereafter, due to 2014 (1)	**47.8**	51.0
At BA rates, due to 2014 (1)	**0.4**	0.6
At 7.56%, due to 2022	**33.1**	34.9
Brighton Beach project financing:		
At 5.8367%, due 2009, at BA or Canadian Eurodollar rates thereafter, due to 2019 (1)	**9.8**	-
At BA or Canadian Eurodollar rates, due to 2019 (1)	**1.3**	-
At 6.575%, due to 2019 (1)	**39.5**	40.7
At 6.924%, due to 2024	**110.6**	110.6
Cory project financing:		
At BA rates, due to 2011 (1)	**0.3**	0.1
At 6.461%, due to 2011 (1)	**3.9**	4.7
At 7.586%, due to 2025	**38.2**	38.8
At 7.601%, due to 2026	**33.7**	34.0
	811.5	852.4
Less: Amounts due within one year	**50.6**	46.3
	$760.9	$806.1

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 1.1% (2003 — 0.9%).

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 95% (2003 — 92%) of total long term debt and non-recourse long term debt.

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2004 was $1,342.5 million (2003 — $1,248.2 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Equity contributions** — Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2004, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is anticipated to be $8.7 million.

b) **Project cash flows** — Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing

agreement depending upon the specific operating results of the plant. At December 31, 2004, no amounts were outstanding under the guarantee.

c) **Reserve amounts** — Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2004, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [1]	$13.7
Joffre project financing	Nil [2]	$ 4.2
Muskeg River project financing	Nil [1]	$ 5.1
Scotford project financing	Nil [1]	$ 5.6

(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $2.7 million met with project cash flows.

d) **Prepaid operating and maintenance fee** — Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2004, the maximum value of the guarantee is $32.4 million.

e) **Purchase project assets** — Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2004, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts. In addition, Canadian Utilities Limited has posted acceptable credit support in the amount of $2.2 million with respect to builders' liens filed against the Cory project.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

11. Long term debt and non-recourse long term debt (continued)

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long term Debt	Total
2005	$130.3	$ 50.6	$180.9
2006	179.5	64.9	244.4
2007	61.5	56.0	117.5
2008	100.0	82.5	182.5
2009	125.0	75.5	200.5
	$596.3	$329.5	$925.8

Of the $180.9 million due in 2005, $125.0 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest on debt is as follows:

	2004	2003
Long term debt	**$147.3**	$144.2
Non-recourse long term debt	**55.6**	55.9
Notes payable	**0.7**	0.6
Current bank indebtedness	**2.8**	5.3
Amortization of financing charges	**3.1**	2.5
Less: Capitalized on non-regulated projects	**(5.8)**	(18.2)
	$203.7	$190.3

Interest paid amounted to $201.2 million (2003 — $207.8 million).

Fair values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

	2004	2003
Long term debt		
Fixed rate	**$2,536.6**	$2,093.3
Floating rate	**16.8**	25.8
	$2,553.4	$2,119.1
Non-recourse long term debt		
Fixed rate	**$ 735.3**	$ 757.8
Floating rate	**122.8**	133.5
	$ 858.1	$ 891.3

12. Deferred credits

	2004	2003
Deferred availability incentives	**$ 46.1**	$ 43.3
Asset retirement obligations	**34.7**	32.3
Deferred electricity cost recoveries	**10.3**	16.2
Deferred royalty credits	**14.1**	10.3
Accrued equipment repairs and maintenance	**10.1**	8.5
Net accrued post employment benefits (Note 19)	**11.6**	8.7
Deferred revenues	**6.4**	0.9
Other	**24.7**	14.9
	$158.0	$135.1

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $7.6 million in 2004 (2003 – $7.5 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

The effect of adopting these recommendations is presented as increases (decreases) below:

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
	(Unaudited)			
Statement of earnings				
Site restoration and removal costs, included in operation and maintenance	**$ -**	$ -	**$ -**	$(0.2)
Depreciation and amortization	**(0.2)**	(0.3)	**(0.8)**	(1.5)
Accretion expense, included in depreciation and amortization	**0.5**	0.4	**1.9**	1.8
Income taxes	**(0.1)**	-	**(0.2)**	(0.1)
Earnings attributable to Class A and Class B shares	**$(0.2)**	$(0.1)	**$(0.9)**	$ -

12. **Deferred credits** (continued)

	January 1 2003
Balance sheet	
Retirement assets and site restoration and removal costs, included in property, plant and equipment	$24.2
Asset retirement obligations, included in deferred credits	30.1
Accrual for future removal and site restoration costs, included in deferred credits	(3.3)
Future income tax liabilities	0.5
Retained earnings at beginning of period	(3.1)

Changes in asset retirement obligations are summarized below:

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
	(Unaudited)			
Obligations at beginning of period	**$34.2**	$31.5	**$32.3**	$30.1
Obligations incurred	**-**	0.4	**0.5**	0.4
Accretion expense	**0.5**	0.4	**1.9**	1.8
Obligations at end of period	**$34.7**	$32.3	**$34.7**	$32.3

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $93 million, which will be incurred between 2005 and 2052. A weighted average discount rate of 5.9% was used to calculate the fair value of the asset retirement obligations.

13. Equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	**2004** Shares	**2004** Amount	2003 Shares	2003 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	**2,277,675**	**$ 56.9**	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	**2,146,730**	**53.7**	2,146,730	53.7
6.6% Series S	$25.00	Open	**635,700**	**15.9**	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
5.05% Series O	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series T	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series U	$25.00	December 2, 2006	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$636.5		$636.5

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

13. Equity preferred shares (continued)

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $669.2 million (2003 — $665.1 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

14. Class A and Class B shares

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2002	40,121,794	$362.1	23,290,391	$147.5	63,412,185	$509.6
Purchased	(73,900)	(0.7)	-	-	(73,900)	(0.7)
Stock options exercised	45,350	1.6	-	-	45,350	1.6
Converted: Class B to Class A	1,040,465	6.6	(1,040,465)	(6.6)	-	-
December 31, 2003	**41,133,709**	**369.6**	**22,249,926**	**140.9**	**63,383,635**	**510.5**
Purchased	**(145,400)**	**(1.3)**	**-**	**-**	**(145,400)**	**(1.3)**
Stock options exercised	**153,300**	**5.1**	**-**	**-**	**153,300**	**5.1**
Converted:Class B to Class A	**228,684**	**1.4**	**(228,684)**	**(1.4)**	**-**	**-**
December 31, 2004	**41,370,293**	**$374.8**	**22,021,242**	**$139.5**	**63,391,535**	**$514.3**

From January 1, 2005 to February 11, 2005, 52,900 Class A non-voting shares were issued with respect to the exercises of stock options and 2,800 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

14. Class A and Class B shares (continued)

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
	(Unaudited)			
Weighted average shares outstanding	**63,373,283**	63,371,535	**63,382,521**	63,389,192
Effect of dilutive stock options	**265,413**	310,985	**249,489**	275,855
Weighted average diluted shares outstanding	**63,638,696**	63,682,520	**63,632,010**	63,665,047

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Normal course issuer bid

On May 20, 2003, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid expired on May 19, 2004. Over the life of the bid, 73,600 shares were purchased, of which 56,600 were purchased in 2003 and 17,000 were purchased in 2004. On May 20, 2004, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid will expire on May 19, 2005. From May 20, 2004, to February 11, 2005, 128,400 shares have been purchased, all of which were purchased in 2004.

15. Stock based compensation plans

Stock option plan

Of the 3,200,000 Class A non-voting shares reserved for issuance in respect of options under Canadian Utilities Limited's stock option plan, 1,467,350 Class A non-voting shares are available for issuance at December 31, 2004. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

15. Stock based compensation plans (continued)

Changes in shares under option are summarized below:

	2004		2003	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**944,450**	**$37.88**	947,800	$37.15
Granted	**3,000**	**52.90**	42,000	51.74
Exercised	**(153,300)**	**32.66**	(45,350)	35.60
Cancelled	**(16,350)**	**41.13**	-	-
Options at end of year	**777,800**	**$38.89**	944,450	$37.88

Information about stock options outstanding at December 31, 2004 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$23.76 - $30.08	181,350	1.3	$27.73	181,350	$27.73
$34.46 - $37.74	251,300	4.9	35.66	249,300	35.64
$41.29 - $57.29	345,150	5.3	47.12	265,300	46.37
$23.76 - $57.29	777,800	4.2	$38.89	695,950	$37.67

In 2004, Canadian Utilities Limited granted 3,000 options to purchase Class A non-voting shares to officers and certain key employees at an exercise price of $52.90 per share. The options have a term of ten years and vest over the first five years.

On January 1, 2005, Canadian Utilities Limited granted 100,000 options to purchase Class A non-voting shares at an exercise price of $60.49 per share. The options have a term of ten years and vest over the first five years.

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for stock based compensation. These recommendations require the expensing of stock options granted on and after January 1, 2002. This retroactive change in accounting had no effect on earnings for the three months ended December 31, 2004 and reduced earnings for the year ended December 31, 2004 by $0.1 million, with no effect on earnings per share in either period, reduced earnings for the three months and year ended December 31, 2003 by $0.1 million and $0.2 million, respectively, with no effect on earnings per share in either period, and resulted in a charge of $0.1 million to retained earnings at January 1, 2003. The prior year's financial statements have been restated for the change in the method of accounting for stock options.

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2004 at $5.67 per option (2003 — $4.68 per option) using the following assumptions:

	2004	2003
Risk free interest rate	**4.2%**	4.3%
Expected holding period prior to exercise	**6.5 years**	5.5 years
Share price volatility	**12.7%**	12.1%
Estimated annual Class A share dividend	**4.0%**	4.0%

15. **Stock based compensation plans** (continued)

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $0.9 million (2003 — $2.4 million).

16. Changes in non-cash working capital

	2004	2003
Operating activities, changes related to:		
Accounts receivable	**$ 217.9**	$(92.0)
Inventories	**(1.3)**	(50.8)
Deferred natural gas costs	**28.1**	4.0
Deferred electricity costs	**10.7**	21.7
Prepaid expenses	**1.4**	(0.8)
Accounts payable and accrued liabilities	**(187.3)**	60.6
Income taxes	**41.8**	9.8
Future income taxes	**(9.0)**	(5.3)
	$ 102.3	$(52.8)
Investing activities, changes related to:		
Inventories	**$ (0.2)**	$ 0.5
Prepaid expenses	**(0.1)**	0.3
Accounts payable and accrued liabilities	**(4.5)**	(30.8)
Income taxes	**11.0**	-
Future income taxes	**(2.8)**	-
	$ 3.4	$(30.0)
Financing activities, changes related to:		
Accounts receivable	**$ (1.8)**	$ 7.9

17. Joint ventures

The Corporation's interest in joint ventures is summarized below:

	2004	2003
Statement of earnings		
Revenues	**$ 452.6**	$ 420.9
Operating expenses	**311.5**	291.7
Depreciation and amortization	**39.2**	34.7
Interest	**39.3**	34.5
	62.6	60.0
Interest and other income	**6.8**	5.7
Earnings from joint ventures before income taxes	**$ 69.4**	$ 65.7
Balance sheet		
Current assets	**$ 241.7**	$ 143.1
Current liabilities	**(138.7)**	(115.3)
Property, plant and equipment	**990.0**	997.5
Deferred items – net	**(140.8)**	(60.0)
Non-recourse long term debt	**(579.6)**	(612.6)
Investment in joint ventures	**$ 372.6**	$ 352.7
Statement of cash flows		
Operating activities	**$ 40.4**	$ 80.7
Investing activities	**(46.6)**	(105.6)
Financing activities	**0.6**	4.5
Foreign currency translation	**(0.4)**	(4.7)
Decrease in cash position	**$ (6.0)**	$ (25.1)

Current assets include cash of $48.7 million (2003 — $54.4 million) which is only available for use within the joint ventures.

18. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $1.8 million (2003 — $2.8 million), recovered administrative expenses totaling $2.7 million (2003 — $3.0 million) and incurred administrative expenses and corporate signature rights totaling $7.1 million (2003 — $6.8 million). The Corporation also incurred advertising and promotion expenses from an entity related through common control totaling $1.1 million (2003 — $1.1 million). These transactions are in the normal course of business and under normal commercial terms.

19. Employee future benefits

The Corporation maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plans and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plans at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases.

19. **Employee future benefits** (continued)

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2004		2003	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,322.5**	**$ -**	$1,195.0	$ -
Actual return on plan assets	**115.8**	**-**	159.1	-
Employee contributions	**5.0**	**-**	5.1	-
Benefit payments	**(36.1)**	**-**	(33.4)	-
Payments to defined contribution plans	**(5.1)**	**-**	(3.3)	-
End of year	**$1,402.1**	**$ -**	$1,322.5	$ -
Accrued benefit obligations:				
Beginning of year	**$1,092.6**	**$ 62.5**	$ 952.0	$ 47.9
Current service cost	**23.6**	**2.0**	20.9	1.9
Interest cost	**69.5**	**3.8**	65.3	3.8
Employee contributions	**5.0**	**-**	5.1	-
Benefit payments from plan assets [1]	**(36.1)**	**-**	(33.4)	-
Benefit payments by employer	**(4.1)**	**(2.0)**	(3.6)	(1.7)
Experience losses [2]	**82.2**	**0.7**	86.3	10.6
End of year	**$1,232.7**	**$ 67.0**	$1,092.6	$ 62.5
Funded status:				
Excess (deficiency) of assets over obligations	**$ 169.4**	**$(67.0)**	$ 229.9	$(62.5)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**310.3**	**14.0**	270.1	13.6
Unrecognized net transitional liability (asset)	**(286.2)**	**25.3**	(319.0)	27.6
Accrued asset (liability)	**193.5**	**(27.7)**	181.0	(21.3)
Regulatory asset (liability) [3]	**(137.6)**	**16.1**	(128.5)	12.6
Net accrued asset (liability) recognized (Notes 9, 12)	**$ 55.9**	**$(11.6)**	$ 52.5	$ (8.7)

(1) Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.

(2) A change in the liability discount rate assumption resulted in experience losses in 2004 of approximately $70.0 million for the pension benefit plans.

(3) The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

19. Employee future benefits (continued)

	2004		2003	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost (income)				
Components of benefit plan cost (income):				
Current service cost	**$ 23.6**	**$ 2.0**	$ 20.9	$ 1.9
Interest cost	**69.5**	**3.8**	65.3	3.8
Actual return on plan assets	**(115.8)**	**-**	(159.1)	-
Experience losses on accrued benefit obligations	**82.2**	**0.7**	86.3	10.6
	59.5	**6.5**	13.4	16.3
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**29.4**	**-**	68.1	-
Unrecognized portion of experience losses on accrued benefit obligations	**(82.2)**	**(0.7)**	(86.3)	(10.6)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**12.7**	**0.3**	13.5	0.4
Amortization of net transitional liability (asset)	**(32.8)**	**2.3**	(32.8)	2.3
	(72.9)	**1.9**	(37.5)	(7.9)
Defined benefit plans cost (income)	**(13.4)**	**8.4**	(24.1)	8.4
Defined contribution plans cost	**6.4**	**-**	4.5	-
Total cost (income)	**(7.0)**	**8.4**	(19.6)	8.4
Less: Capitalized	**1.2**	**2.0**	1.0	2.0
Less: Unrecognized defined benefit plans cost (income) [1]	**(10.2)**	**2.5**	(19.5)	2.5
Net cost (income) recognized	**$ 2.0**	**$ 3.9**	$ (1.1)	$ 3.9

(1) The unrecognized defined benefit plans cost (income) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

In the unaudited three months ended December 31, 2004, net cost of $0.6 million (2003 – $0.7 million income) was recognized for pension benefit plans and net cost of $1.0 million (2003 – $1.3 million) was recognized for other post employment benefit plans.

19. Employee future benefits (continued)

Weighted average assumptions

	2004		2003	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost (income):				
Expected long term rate of return on plan assets for the year	**7.25%**	**-**	7.5%	-
Liability discount rate for the year	**6.25%**	**6.25%**	6.5%	6.5%
Average compensation increase for the year	**3.0%**	**-**	2.75%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.9%**	**5.9%**	6.25%	6.25%
Long term inflation rate	**2.5%**	(1)	2.5%	(1)

(1) The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 9.9% for 2004 grading down over 9 years to 4.5% (2003 – 10.5% for 2003 grading down over 10 years to 4.5%), and, for other medical and dental costs, 4.0% for 2004 and thereafter (2003 – 4.0% for 2003 and thereafter).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2004 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2004 Pension Benefit Plans		2004 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost (Income)	Accrued Benefit Obligation	Benefit Plan Cost (Income)
Expected long term rate of return on plan assets				
1% increase (1)	-	$(3.3)	-	-
1% decrease (1)	-	$ 3.3	-	-
Liability discount rate				
1% increase (1)	$(51.8)	$(4.8)	$(2.6)	$(0.2)
1% decrease (1)	$ 65.3	$ 5.9	$ 3.3	$ 0.3
Future compensation rate				
1% increase (1)	$ 17.9	$ 2.6	-	-
1% decrease (1)	$(13.8)	$(2.0)	-	-
Long term inflation rate				
1% increase (1) (2) (3)	$ 21.5	$ 2.8	$ 2.9	$ 0.5
1% decrease (1) (3)	$(38.0)	$(5.0)	$(2.4)	$(0.4)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost (income), which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

(3) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

19. Employee future benefits (continued)

Pension benefit plan assets

	2004		2003	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 809.2**	**57.7**	$ 817.3	61.8
Fixed income securities [2]	**507.2**	**36.2**	442.4	33.4
Real estate [3]	**34.4**	**2.4**	31.1	2.4
Cash and other assets [4]	**51.3**	**3.7**	31.7	2.4
	$1,402.1	**100.0**	$1,322.5	100.0

(1) Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2004 the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $134.4 million and $151.6 million, respectively (2003 – $134.4 million and $148.7 million, respectively).

(2) Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.

(3) Real estate consists of investments in closed-end real estate funds.

(4) Cash and other assets consist of cash, short term notes and money market funds.

At December 31, 2004, plan assets include long term debt of CU Inc. having a market value of $5.3 million (2003 – $1.8 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $12.4 million (2003 – $11.6 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of $10.6 million (2003 – $8.7 million).

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2002, the Corporation is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2005.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by the Corporation out of general revenues. These supplementary plans had accrued benefit obligations of $71.5 million at December 31, 2004 (2003 – $70.9 million).

20. Risk management and financial instruments

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the United Kingdom and the Global Enterprises segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

20. Risk management and financial instruments (continued)

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Completion Date	Principal/Face Value	
			2004	2003
6.435%	90 day BA	December 2004	**$ -**	$ 2.3
5.247%	90 day BA	December 2007	**47.8**	51.0
5.202%	90 day BA	September 2008	**63.7**	67.6
7.54%	90 day BA	November 2008	**5.1**	6.4
7.317%	90 day BA	December 2008	**8.1**	9.0
5.837%	90 day BA	June 2009	**9.8**	-
6.461%	90 day BA	June 2011	**3.9**	4.7
7.50%	6 month LIBOR	December 2011	**90.6**	93.1
7.286%	90 day BA	September 2012	**32.5**	34.3
7.3325%	Bank Bill Rate in Australia	December 2013	**42.6**	51.6
6.575%	90 day BA	March 2019	**39.5**	40.7
			$343.6	$360.7

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees (Note 11).

Foreign exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates.

The Corporation has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars. At December 31, 2004, there were no contracts outstanding to purchase U.S. dollars (2003 — $0.5 million U.S.).

Energy commodity price risk

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year, which ends on March 31, 2005. The decision directed ATCO Gas to continue to reserve 16.7 petajoules of storage capacity for the benefit of utility customers. As a result of an AEUB approved storage plan, ATCO Gas has entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes. All associated costs and benefits of these contracts are passed to customers through regulated rates, and accordingly, ATCO Gas does not bear any risk for price fluctuations provided that the contracts are in accordance with the storage plan. At December 31, 2004, the contracts consist of natural gas sales of 12,802 terajoules ("TJ") for $76.3 million (2003 — 151 TJ for $1.0 million) and natural gas purchases of 107 TJ for $0.6 million (2003 — 151 TJ for $1.0 million).

20. Risk management and financial instruments (continued)

Fair values

The fair values of derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

	2004			2003		
	Notional Principal	**Fair Value (Payable) Receivable**	**Maturity**	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	**$343.6**	**$(16.0)**	**2007-2019**	$360.7	$(14.0)	2004-2019
Foreign exchange forward contracts	-	-	-	$ 0.7	Nil	2004

Credit risk

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

21. Commitments and contingencies

Commitments

The Corporation has contractual obligations in the normal course of business, including long term operating leases for office premises and equipment. Future minimum lease payments are as follows:

2005	2006	2007	2008	2009	Total of All Subsequent Years
$15.0	$14.0	$12.7	$11.9	$4.9	$9.4

Contingencies

The Corporation is party to a number of disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

As a result of recent decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

22. Regulatory matters

In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations and 35% for its distribution operations for 2003. These reductions in the common equity ratios reduced the common equity that ATCO Electric was allowed to earn a return on by $83.0 million for 2003. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress. In a decision dated July 2, 2004, the AEUB issued its Generic Cost of Capital decision (as described below) which approved, among other things, a return on common equity of 9.60% for 2004 and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric was allowed to earn a return on by $22.3 million for 2004 as compared to 2003.

In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress. In a decision dated July 2, 2004, the AEUB issued its Generic Cost of Capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB in its Generic Cost of Capital decision for determining the return on common equity will be applied beginning in 2005.

In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress. In a decision dated July 2, 2004, the AEUB issued its Generic Cost of Capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

The Generic Cost of Capital decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return will be adjusted annually by 75% of the change in long term Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005. The AEUB also announced that the 2005 generic return on equity would only apply to utilities which file rate applications in 2005. If no rate applications are filed, then existing return on common equity rates will continue to apply.

The Corporation has a number of other regulatory filings and regulatory hearing submissions before the AEUB for which decisions have not been received. The outcome of these matters cannot be determined at this time.

23. Segmented information

Description of segments

In August 2004, the Corporation reorganized its management reporting structure into the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated complementary projects by ATCO Utility Services.

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek's subsidiary, ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Fort McMurray, Alberta.

2003 segmented figures have been restated to conform to the current basis of segmentation.

Segmented results – Three months ended December 31

2004 2003	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$293.8** $650.0	**$183.9** $171.9	**$184.5** $128.0	**$ 0.4** $ 0.4	**$ -** $ -	**$662.6** $950.3
Revenues – intersegment [1]	**4.1** 6.2	**-** -	**29.3** 195.2	**3.5** 2.6	**(36.9)** (204.0)	**-** -
Revenues	**$297.9** $656.2	**$183.9** $171.9	**$213.8** $323.2	**$ 3.9** $ 3.0	**$ (36.9)** $(204.0)	**$662.6** $950.3
Earnings attributable to Class A and Class B shares	**$ 38.5** $ 41.1	**$ 24.1** $ 35.7	**$ 30.8** $ 14.4	**$(3.6)** $(5.0)	**$ 0.5** $ 0.3	**$ 90.3** $ 86.5

(1) Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

23. Segmented information (continued)

Segmented results – Year ended December 31

2004 2003	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,771.6** $2,525.6	**$ 653.2** $ 643.4	**$ 663.5** $ 572.6	**$ 1.2** $ 1.0	**$ -** $ -	**$3,089.5** $3,742.6
Revenues – intersegment [1]	**18.2** 23.0	**-** -	**334.7** 653.0	**10.4** 11.2	**(363.3)** (687.2)	**-** -
Revenues	**1,789.8** 2,548.6	**653.2** 643.4	**998.2** 1,225.6	**11.6** 12.2	**(363.3)** (687.2)	**3,089.5** 3,742.6
Operating expenses	**1,328.6** 2,077.5	**346.7** 351.8	**867.2** 1,118.0	**11.2** 14.6	**(368.1)** (693.2)	**2,185.6** 2,868.7
Depreciation and amortization	**178.9** 166.1	**89.5** 78.3	**22.0** 24.3	**1.1** 0.5	**-** -	**291.5** 269.2
Interest expense	**118.8** 114.0	**84.5** 75.2	**2.4** 2.7	**148.0** 145.6	**(150.0)** (147.2)	**203.7** 190.3
Gain on transfer of retail energy supply businesses	**(63.3)** -	**-** -	**-** -	**-** -	**-** -	**(63.3)** -
Interest and other income	**(8.6)** (8.8)	**(7.9)** (7.5)	**(2.4)** (5.9)	**(161.9)** (158.4)	**150.0** 147.2	**(30.8)** (33.4)
Earnings before income taxes	**235.4** 199.8	**140.4** 145.6	**109.0** 86.5	**13.2** 9.9	**4.8** 6.0	**502.8** 447.8
Income taxes	**56.3** 68.1	**56.8** 49.2	**36.9** 30.4	**6.2** 5.8	**1.8** 2.1	**158.0** 155.6
	179.1 131.7	**83.6** 96.4	**72.1** 56.1	**7.0** 4.1	**3.0** 3.9	**344.8** 292.2
Dividends on equity preferred shares	**10.4** 10.4	**3.6** 3.6	**-** -	**21.8** 19.1	**-** -	**35.8** 33.1
Earnings attributable to Class A and Class B shares	**$ 168.7** $ 121.3	**$ 80.0** $ 92.8	**$ 72.1** $ 56.1	**$ (14.8)** $ (15.0)	**$ 3.0** $ 3.9	**$ 309.0** $ 259.1
Total assets	**$3,405.6** $3,418.5	**$2,210.3** $2,215.7	**$ 307.8** $ 320.9	**$528.3** $185.7	**$ 11.1** $ (44.3)	**$6,463.1** $6,096.5
Purchase of property, plant and equipment	**$ 426.3** $ 347.9	**$ 77.0** $ 131.7	**$ 14.5** $ 15.5	**$ 17.7** $ 0.6	**$ -** $ -	**$ 535.5** $ 495.7

(2) Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

Geographic segments

	Domestic		Foreign		Consolidated	
	2004	2003	**2004**	2003	**2004**	2003
Revenues	**$2,868.7**	$3,504.3	**$220.8**	$238.3	**$3,089.5**	$3,742.6
Property, plant and equipment	**$4,690.9**	$4,462.3	**$354.4**	$373.1	**$5,045.3**	$4,835.4

24. TXU Europe settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement has now been reached with respect to Barking Power's claim. This agreement is reflected in the company voluntary arrangements ("CVA's") which were approved on January 28, 2005.

On February 3, 2005, the Corporation announced that at TXU creditors' and members' meetings on January 28, 2005, CVA's under the United Kingdom Insolvency Act were approved in respect of certain TXU companies, including TXU Europe Energy Trading Limited and TXU Europe Group plc.

The CVA's will not become effective until on or about February 28, 2005, and any additional creditors are entitled to make claims until on or about March 15, 2005. The impact of the CVA's on the Corporation's financial condition and results cannot be determined at this time, but is expected to be positive.

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD&A")

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited comparative interim financial statements for the three months ended December 31, 2004, and the audited comparative financial statements for the year ended December 31, 2004. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

All quarterly information in this document is shaded to differentiate it from the annual information.

The common share capital of the Corporation consists of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to purchase obligations, planned capital expenditures, anticipated completion dates and construction costs of major projects, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other (refer to Note 23 to the comparative financial statements). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

In August 2004, the Corporation reorganized its management reporting structure into the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated complementary projects by ATCO Utility Services.

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek's subsidiary, ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Fort McMurray, Alberta.

TRANSFER OF THE RETAIL ENERGY SUPPLY BUSINESSES

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc ("Transfer of the Retail Energy Supply Businesses"). Proceeds of the transfer were $90 million, of which $45 million was paid at closing, with the remainder to be paid 12 months following closing. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of $63.3 million before income taxes of $8.2 million. This transfer increased 2004 earnings by $55.1 million.

The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004, will be reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There will be no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions (the "transferred functions").

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm, commercial and small industrial customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the Alberta Energy and Utilities Board ("AEUB") to do so), the agreements will terminate and the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below $200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

DEML has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek Business Services to provide billing and call centre services to ensure continued quality customer service. DEML has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

SELECTED ANNUAL AND QUARTERLY INFORMATION

($ Millions except per share data)	For the Three Months Ended Mar. 31	Jun. 30	Sep. 31	Dec. 31	Year Ended Dec. 31
	(unaudited)				
2004					
Revenues (1)	1,185.9	690.2	550.8	662.6	3,089.5
Earnings attributable to Class A and Class B shares (2) (5) (6)	74.5	100.2	44.0	90.3	309.0
Earnings per Class A and Class B share (2) (5) (6)	1.17	1.58	0.70	1.43	4.88
Diluted earnings per Class A and Class B share (2) (5) (6)	1.16	1.58	0.70	1.42	4.86
2003					
Revenues	1,372.2	797.5	622.6	950.3	3,742.6
Earnings attributable to Class A and Class B shares (3) (5) (6)	85.9	43.5	43.2	86.5	259.1
Earnings per Class A and Class B share (3) (5) (6)	1.35	0.69	0.68	1.37	4.09
Diluted earnings per Class A and Class B share (3) (5) (6)	1.34	0.69	0.68	1.36	4.07
2002					
Revenues	....	....	....	....	2,975.9
Earnings attributable to Class A and Class B shares (3) (4) (5) (6)	....	....	....	....	306.1
Earnings per Class A and Class B share (3) (4) (5) (6)	....	....	....	....	4.83
Diluted earnings per Class A and Class B share (3) (4) (5) (6)	....	....	....	....	4.81

Notes:

(1) *Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004, September 30, 2004 and December 31, 2004.*

(2) *Includes earnings of $55.1 million, earnings per share of $0.87 per share and diluted earnings per share of $0.87 on the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004, and for year ended December 31, 2004.*

(3) *2003 and 2002 earnings attributable to Class A and Class B shares have been restated for retroactive changes in the methods of accounting for asset retirement obligations and stock based compensation.*

(4) *Includes earnings of $67.3 million, earnings per share of $1.06 per share and diluted earnings per share of $1.06 on the sale of the Viking-Kinsella natural gas producing property for the year ended December 31, 2002.*

(5) *There were no discontinued operations or extraordinary items during these periods.*

(6) *Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.*

(7) *The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.*

	Year Ended December 31		
	2004	2003	2002
	($ Millions except per share data)		
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O	1.26	1.26	1.26
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T	1.26	1.26	1.26
Series U	1.26	1.26	1.26
Series V (1)	1.31	1.31	1.20
Series W (2)	1.45	1.44	-
Series X (3)	1.50	0.93	-
Class A and Class B shares	2.12	2.04	1.96
Total assets	6,463.1	6,096.5	5,958.6
Long term debt	2,171.0	1,805.3	1,916.9
Non-recourse long term debt	760.9	806.1	821.1
Equity preferred shares	636.5	636.5	486.5
Class A and Class B share owners' equity	2,117.7	1,948.5	1,827.0

Notes:

(1) The dividend was reset to $1.31 (5.25%) for the period between October 3, 2002 and October 3, 2007.

(2) Issued December 3, 2002.

(3) Issued April 17, 2003.

(4) The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

RESULTS OF OPERATIONS

The principal factors that have caused variations in **revenues** over the eight most recently completed quarters were:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses section), and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004 (refer to the Utilities section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section);
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections); and
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004 (refer to the Power Generation section).

The principal factors that have caused variations in **earnings** over the eight most recently completed quarters were:

- the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses and the Utilities sections);
- fluctuations in electricity prices and related spark spreads in Alberta for ATCO Power (refer to the Power Generation section);
- fluctuations in temperatures (refer to the Utilities section); and
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections).

Consolidated Operations

Revenues for the three months ended December 31, 2004, decreased by $287.7 million to $662.6 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses;
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004;
- planned maintenance outage at ATCO Power's Osborne generating plant in Australia during the fourth quarter of 2004. This outage began in October and was completed by the end of November; and
- warmer temperatures in ATCO Gas, which were 9.8% warmer than normal, compared to 3.2% warmer than normal for the corresponding period in 2003.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream;
- the ATCO Pipelines Decision (refer to Regulatory Matters - ATCO Pipelines section);
- increased business activity and the commencement of work for new customers by ATCO I-Tek;
- operations at ATCO Power's new 170 megawatt Scotford generating plant commissioned in December 2003 and its new 580 megawatt Brighton Beach generating plant commissioned in July 2004; and
- improved performance in ATCO Power's United Kingdom ("U.K.") operations.

Revenues for the year ended December 31, 2004, decreased by $653.1 million to $3,089.5 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas, which were 3.0% warmer than normal, compared to 3.4% colder than normal in 2003;
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004;
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue); and
- lower prices received for electricity sold to the Alberta Electric System Operator ("AESO") by ATCO Power.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream;
- operations at ATCO Power's new Scotford and Brighton Beach generating plants;
- customer additions in ATCO Gas;
- increased business activity and the commencement of work for new customers by ATCO I-Tek;
- the ATCO Pipelines Decision; and
- improved performance in ATCO Power's U.K. operations.

Earnings attributable to Class A and Class B shares for the three months ended December 31, 2004, increased by $3.8 million ($0.06 per share) to $90.3 million ($1.43 per share), primarily due to:

- the ATCO Pipelines Decision;
- higher margins on natural gas liquids and higher earnings in storage operations in ATCO Midstream;
- increased business activity and the commencement of work for new customers by ATCO I-Tek;
- lower income tax rates; and
- improved earnings in ATCO Power's U.K. operations.

This increase was partially offset by:

- a favourable one-time tax adjustment in Australia in 2003 for ATCO Power ($8.9 million);
- higher transportation costs in ATCO Pipelines;

- warmer temperatures in ATCO Gas; and
- the ATCO Gas Decision (refer to Regulatory Matters - ATCO Gas section).

Earnings attributable to Class A and Class B shares for the year ended December 31, 2004, **including** the $55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, increased by $49.9 million ($0.79 per share) to $309.0 million ($4.88 per share).

Earnings attributable to Class A and Class B shares for the year ended December 31, 2004, **excluding** the $55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, decreased by $5.2 million ($0.08 per share) to $253.9 million ($4.01 per share), primarily due to:

- a favourable one-time tax adjustment in Australia in 2003 for ATCO Power ($8.9 million);
- decrease in ATCO Power's earnings of $8.0 million due to lower prices on electricity sold to the AESO and the related spark spread (as defined in the Power Generation section);
- warmer temperatures in ATCO Gas;
- the ATCO Electric Decision (refer to Regulatory Matters - ATCO Electric section); and
- higher transportation costs in ATCO Pipelines.

This decrease was partially offset by:

- lower income tax rates;
- higher margins on natural gas liquids and higher earnings in storage operations in ATCO Midstream;
- improved earnings in ATCO Power's U.K. operations;
- the ATCO Pipelines Decision;
- increased business activity and the commencement of work for new customers by ATCO I-Tek;
- customer additions in ATCO Gas; and
- operations at ATCO Power's new Scotford and Brighton Beach generating plants.

Return on common equity was 15.2% in 2004.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2004, decreased by $317.9 million to $396.9 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses;
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service only contracts (transportation costs);
- lower selling and administrative costs, primarily in ATCO Gas and ATCO Electric; and
- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher natural gas volumes purchased for natural gas liquids extraction by ATCO Midstream;
- higher franchise fees in ATCO Gas;
- higher fuel costs in ATCO Power's Alberta generating plants due to higher prices, and the commencement of operations at the new Scotford and Brighton Beach generating plants; and
- higher transportation costs in ATCO Pipelines.

Operating expenses for the year ended December 31, 2004, decreased by $683.1 million to $2,185.6 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower costs of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas;
- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and

- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service only contracts (transportation costs).

This decrease was partially offset by:

- higher natural gas volumes purchased for natural gas liquids extraction by ATCO Midstream;
- customer additions in ATCO Gas;
- higher transportation costs in ATCO Pipelines;
- higher fuel and operating costs due to the commencement of operations at ATCO Power's new Scotford and Brighton Beach generating plants; and
- higher franchise fees in ATCO Gas.

Depreciation and amortization expenses for the three months ended December 31, 2004, increased by $8.4 million to $81.2 million, primarily due to:

- capital additions in 2004 and 2003.

Depreciation and amortization expenses for the year ended December 31, 2004, increased by $22.3 million to $291.5 million, primarily due to:

- capital additions in 2004 and 2003.

Interest expense for the three months ended December 31, 2004, increased by $5.8 million to $52.9 million, primarily due to:

- interest on non-recourse financings for ATCO Power's new Scotford and Brighton Beach generating plants commissioned in December 2003 and July 2004, respectively; and
- interest on new financings issued in 2004 to fund capital expenditures in Utilities operations.

Interest expense for the year ended December 31, 2004, increased by $13.4 million to $203.7 million, primarily due to:

- interest on non-recourse financings for ATCO Power's new Oldman River, Scotford and Brighton Beach generating plants commissioned in July 2003, December 2003 and July 2004, respectively; and
- interest on new financings issued in 2004 to fund capital expenditures in Utilities operations.

Interest and other income for the three months ended December 31, 2004, increased by $0.9 million to $10.4 million, primarily due to:

- interest income on higher cash balances.

Interest and other income for the year ended December 31, 2004, decreased by $2.6 million to $30.8 million, primarily due to:

- higher gains on disposals of property, plant and equipment in 2003.

This decrease was partially offset by:

- interest income on higher cash balances.

Income taxes for the three months ended December 31, 2004, increased by $13.1 million to $42.8 million, primarily due to:

- a favourable one-time tax adjustment in Australia in 2003 for ATCO Power; and
- a favourable one-time tax adjustment in 2003 for ATCO Pipelines, resulting from a change in income tax methodology as directed by the AEUB in the ATCO Pipelines Decision.

This increase was partially offset by:

- lower income tax rates; and
- a favourable one-time tax adjustment in 2004 for ATCO Gas, resulting from a change in income tax methodology as directed by the AEUB in the ATCO Gas Decision.

Income taxes for the year ended December 31, 2004, **including** the $8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, increased by $2.4 million to $158.0 million.

Income taxes for the year ended December 31, 2004, **excluding** the $8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, decreased by $5.8 million to $149.8 million, primarily due to:

- lower income tax rates; and
- a favourable one-time tax adjustment in 2004 for ATCO Gas.

This decrease was partially offset by:

- a favourable one-time tax adjustment in Australia in 2003 for ATCO Power; and
- a favourable one-time tax adjustment in 2003 for ATCO Pipelines.

Dividends on equity preferred shares for the year ended December 31, 2004, increased by $2.7 million to $35.8 million as a result of:

- issue of $150.0 million of 6.00% Cumulative Redeemable Second Preferred Shares Series X ("Series X Preferred Shares") in April 2003.

Segmented Information

Segmented revenues for the three months and for the year ended December 31, 2004, were as follows:

	For the Three Months Ended December 31		**For the Year Ended December 31**	
($ Millions)	**2004**	2003	**2004**	2003
	(unaudited)			
Utilities (1)	**297.9**	656.2	**1,789.8**	2,548.6
Power Generation	**183.9**	171.9	**653.2**	643.4
Global Enterprises	**213.8**	323.2	**998.2**	1,225.6
Corporate and Other	**3.9**	3.0	**11.6**	12.2
Intersegment eliminations	**(36.9)**	(204.0)	**(363.3)**	(687.2)
Total	**662.6**	950.3	**3,089.5**	3,742.6

Note:

(1) *Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three months and for the year ended December 31, 2004.*

Segmented earnings attributable to Class A and Class B shares for the three months and for the year ended December 31, 2004, were as follows:

($ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2004	2003	**2004**	2003
	(unaudited)			
Utilities (1)	**38.5**	41.1	**168.7**	121.3
Power Generation (2)	**24.1**	35.7	**80.0**	92.8
Global Enterprises (2)	**30.8**	14.4	**72.1**	56.1
Corporate and Other (3)	**(3.6)**	(5.0)	**(14.8)**	(15.0)
Intersegment eliminations	**0.5**	0.3	**3.0**	3.9
Total	**90.3**	86.5	**309.0**	259.1

Notes:

(1) *The earnings for the year ended December 31, 2004, include earnings of $55.1 million from the Transfer of the Retail Energy Supply Businesses.*

(2) *2003 earnings have been restated for a retroactive change in the method of accounting for asset retirement obligations.*

(3) *2003 earnings have been restated for a retroactive change in the method of accounting for stock based compensation.*

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2004, decreased by $358.3 million to $297.9 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses; and
- warmer temperatures in ATCO Gas, which were 9.8% warmer than normal, compared to 3.2% warmer than normal for the corresponding period in 2003.

This decrease was partially offset by:

- the ATCO Pipelines Decision (refer to Regulatory Matters - ATCO Pipelines section).

Revenues for the year ended December 31, 2004, decreased by $758.8 million to $1,789.8 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas, which were 3.0% warmer than normal, compared to 3.4% colder than normal in 2003; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- customer additions in ATCO Gas; and
- the ATCO Pipelines Decision.

Earnings for the three months ended December 31, 2004, decreased by $2.6 million to $38.5 million, primarily due to:

- higher transportation costs in ATCO Pipelines;
- warmer temperatures in ATCO Gas; and
- the ATCO Gas Decision (refer to Regulatory Matters - ATCO Gas section).

This decrease was partially offset by:

- the ATCO Pipelines Decision.

Earnings for the year ended December 31, 2004, **including** the $55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, increased by $47.4 million to $168.7 million.

Earnings for the year ended December 31, 2004, **excluding** the $55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, decreased by $7.7 million to $113.6 million, primarily due to:

- warmer temperatures in ATCO Gas;
- the ATCO Electric Decision (refer to Regulatory Matters - ATCO Electric section); and
- higher transportation costs in ATCO Pipelines.

This decrease was partially offset by:

- the ATCO Pipelines Decision;
- customer additions in ATCO Gas; and
- lower income tax rates.

Operating expenses for the year ended December 31, 2004, decreased by $748.9 million to $1,328.6 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower costs of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service only contracts (transportation costs).

This decrease was partially offset by:

- customer additions in ATCO Gas;
- higher transportation costs in ATCO Pipelines; and
- higher franchise fees in ATCO Gas.

In the first quarter of 2003, ATCO Gas commenced the first phase of a $278 million project to relocate natural gas meters currently inside homes to the outside. The project will make the distribution system safer by relocating and replacing aging infrastructure, improve metering accuracy and accessibility, and facilitate more efficient meter reading. The ATCO Gas Decision approved a program which will result in meters with underground entries being relocated over 10 years and all other inside meters moved as part of the existing meter recall program. The decision also allows ATCO Gas to move meters at any time if they are deemed unsafe.

On August 30, 2004, ATCO Electric completed construction of a $99.0 million, 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake. The project included three substations and the expansion of an existing substation. Construction was completed in 10 months. Typically, a project of this scale and complexity is constructed over two years.

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2004, increased by $12.0 million to $183.9 million, primarily as a result of:

- operations at ATCO Power's new 170 megawatt Scotford generating plant commissioned in December 2003 and its new 580 megawatt Brighton Beach generating plant commissioned in July 2004;
- improved performance in ATCO Power's United Kingdom ("U.K.") operations; and
- higher capacity and energy charges in Alberta Power (2000).

This increase was partially offset by:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and

- planned maintenance outage at ATCO Power's Osborne generating plant in Australia during the fourth quarter of 2004. This outage began in October and was completed by the end of November.

Revenues for the year ended December 31, 2004, increased by $9.8 million to $653.2 million, primarily as a result of:

- operations at ATCO Power's new Scotford and Brighton Beach generating plants;
- improved performance in ATCO Power's U.K. operations; and
- higher capacity and energy charges in Alberta Power (2000).

This increase was partially offset by:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and
- lower prices received for electricity sold to the AESO by ATCO Power.

Earnings for the three months ended December 31, 2004, decreased by $11.6 million to $24.1 million, primarily due to:

- a favourable one-time tax adjustment in Australia in 2003 for ATCO Power ($8.9 million); and
- planned maintenance outage at ATCO Power's Osborne generating plant in Australia.

This decrease was partially offset by:

- improved earnings in ATCO Power's U.K. operations; and
- operations at ATCO Power's new Scotford and Brighton Beach generating plants.

AESO electricity prices for the three months ended December 31, 2004, averaged $55.07 per megawatt hour, compared to average prices of $54.71 per megawatt hour for the corresponding period in 2003. Natural gas prices for the three months ended December 31, 2004, averaged $6.16 per gigajoule, compared to average prices of $5.60 per gigajoule for the corresponding period in 2003. The consequence of stable electricity prices and slightly higher natural gas prices was an average spark spread of $8.87 per megawatt hour for the three months ended December 31, 2004, compared to $13.46 per megawatt hour for the corresponding period in 2003.

Spark spread is related to the difference between AESO electricity prices and the marginal cost of producing electricity from natural gas.

Changes in spark spread affect the results of operation of approximately 300 megawatts of plant capacity owned in Alberta by ATCO Power out of a total world wide owned capacity of approximately 1,318 megawatts.

Earnings for the year ended December 31, 2004, decreased by $12.8 million to $80.0 million, primarily due to:

- a favourable one-time tax adjustment in Australia in 2003 for ATCO Power ($8.9 million);
- decrease in ATCO Power's earnings of $8.0 million due to lower prices on electricity sold to the AESO and the related spark spread.

  AESO electricity prices in 2004 averaged $54.59 per megawatt hour, compared to average prices of $62.99 per megawatt hour in 2003. Natural gas prices in 2004 averaged $6.19 per gigajoule, compared to average prices of $6.31 per gigajoule in 2003. The consequence of relatively weaker electricity prices was an average spark spread of $8.16 per megawatt hour in 2004, compared to $15.69 per megawatt hour in 2003; and

- lower earnings from the transmission must run ("TMR") contracts that were not renewed in May 2004 at the Rainbow Lake IV and V generating plants. The TMR service was conscripted at reduced load levels by the AESO under AEUB regulated terms and conditions up until December 17, 2004, at which time the AESO and ATCO Power agreed to a contract under which the service would be dispatched at full load until December 31, 2005. Compensation under this contract is subject to the AEUB's decision on the AESO's pending application to amend the regulated terms and conditions for conscripted service.

This decrease was partially offset by:

- improved earnings in ATCO Power's U.K. operations; and
- operations at ATCO Power's new Scotford and Brighton Beach generating plants.

Operating expenses for the year ended December 31, 2004, decreased by $5.1 million to $346.7 million, primarily due to:

- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher fuel and operating costs due to the commencement of operations at ATCO Power's new Scotford and Brighton Beach generating plants.

During the three months ended December 31, 2004, Alberta Power (2000)'s **deferred availability incentive** account increased by $8.1 million to $46.1 million. The increase was primarily due to additional availability incentive payments received for improved plant availability. During the three months ended December 31, 2004, the amortization of deferred availability incentives, recorded in revenues, increased by $0.2 million to $2.0 million.

During the year ended December 31, 2004, the **deferred availability incentive** account increased by $2.8 million to $46.1 million. The increase was primarily due to the Battle River arbitration decision (refer to Business Risks-Alberta Power (2000) section), partially offset by amortization of deferred availability incentives, recorded in revenues, of $7.6 million.

On January 29, 2004, the H.R. Milner generating plant was sold by the Alberta Balancing Pool to a third party and the contract under which Alberta Power (2000) had operated the plant on a cost of service basis since January 2001 was terminated. As part of the sale, Alberta Power (2000) was relieved of all decommissioning and reclamation obligations, including any environmental liabilities.

A partnership formed by ATCO Power, ATCO Resources and Ontario Power Generation owns and operates the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant in Windsor, Ontario. Commercial operation of the plant commenced in July 2004.

ATCO Power and SaskPower International Inc. announced in September 2004 that they would not proceed with their joint venture to build 150 megawatts of wind generation in Saskatchewan.

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement has now been reached with respect to Barking Power's claim. This agreement is reflected in the company voluntary arrangements ("CVAs") which were approved on January 28, 2005.

On February 3, 2005, the Corporation announced that at TXU creditors' and members' meetings on January 28, 2005, CVAs under the United Kingdom Insolvency Act were approved in respect of certain TXU companies, including TXU Europe Energy Trading Limited and TXU Europe Group plc.

The CVAs will not become effective until on or about February 28, 2005, and any additional creditors are entitled to make claims until on or about March 15, 2005. The impact of the CVAs on the Corporation's financial condition and results cannot be determined at this time, but is expected to be positive.

The Barking generating plant has continued to supply 725 megawatts of power under long term contracts with other purchasers. The 275 megawatts of power previously supplied to TXU Europe is currently being sold into the United Kingdom ("U.K.") electricity market on a merchant basis under a one year marketing agreement.

At December 31, 2004, all of ATCO Power's non-regulated independent generating plants were in service.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended December 31, 2004, decreased by $109.4 million to $213.8 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Revenues for the year ended December 31, 2004, decreased by $227.4 million to $998.2 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Earnings for the three months ended December 31, 2004, increased by $16.4 million to $30.8 million, primarily due to:

- higher margins on natural gas liquids and higher earnings in storage operations in ATCO Midstream; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Earnings for the year ended December 31, 2004, increased by $16.0 million to $72.1 million, primarily due to:

- higher margins on natural gas liquids and higher earnings in storage operations in ATCO Midstream; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Operating expenses for the year ended December 31, 2004, decreased by $250.8 million to $867.2 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses.

This decrease was partially offset by:

- higher natural gas volumes purchased for natural gas liquids extraction by ATCO Midstream.

Corporate and Other

Earnings for the three months ended December 31, 2004, increased by $1.4 million to $(3.6) million, primarily due to:

- lower income taxes; and
- interest income on higher cash balances.

Earnings for the year ended December 31, 2004, increased by $0.2 million to $(14.8) million, primarily due to:

- decreased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting share prices since December 31, 2003.

This increase was partially offset by:

- increased dividends on equity preferred shares, net of investment income, due to the issue in April 2003 of the Series X Preferred Shares.

ATCOR Resources Ltd. Tax Reassessment

In 2001, the Corporation received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. The Corporation did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities.

During 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. The Federal Government appealed the Tax Court's decision to the Federal Court of Appeal, which issued a decision on June 18, 2004 in favor of the Corporation. The Federal Government did not appeal the Federal Court of Appeal's decision to the Supreme Court of Canada. The Corporation has received a refund of $15.1 million, including interest, and has reversed the future income tax reduction of $12.9 million

REGULATORY MATTERS

Regulated operations are conducted by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

In July 2004, the AEUB issued its generic cost of capital decision. The decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return will be adjusted annually by 75% of the change in long term Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005. The AEUB also announced that the 2005 generic return on equity would only apply to utilities which file rate applications in 2005. If no rate applications are filed, then existing return on common equity rates will continue to apply.

ATCO Electric

In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations and 35% for its distribution operations for 2003. These reductions in the common equity ratios reduced the common equity that ATCO Electric was allowed to earn a return on by $83.0 million for 2003. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress.

In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, a return on common equity of 9.60% and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric was allowed to earn a return on by $22.3 million for 2004 as compared to 2003.

ATCO Electric's October 2, 2003, and July 2, 2004, decisions are referred to in this MD&A as the "ATCO Electric Decision".

ATCO Gas

In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress.

In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB in its generic cost of capital decision (as described above) for determining the return on common equity will be applied beginning in 2005.

ATCO Gas' October 1, 2003, and July 2, 2004, decisions are referred to in this MD&A as the "ATCO Gas Decision".

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition) and allocated $4.1 million of the proceeds to customers and $1.8 million to ATCO Gas. In January 2004, the Alberta Court of Appeal overturned this decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas. The City of Calgary has appealed this decision to the Supreme Court of Canada, which has also granted ATCO Gas leave to cross-appeal the decision. Accordingly, ATCO Gas has not yet recorded the impact of the Alberta Court of Appeal decision.

In March 2004, the AEUB directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ends on March 31, 2005, and allowed ATCO Midstream to continue to utilize the remaining uncontracted capacity at a rate of $0.45 per gigajoule, up from $0.41 per gigajoule. ATCO Gas has been granted leave to appeal this AEUB decision to the Alberta Court of Appeal. A hearing date has not yet been determined.

In July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the Carbon storage facility.

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances that have impacted ATCO Gas' deferred gas account. The application requests a recovery of approximately $11.3 million from ATCO Gas' south customers, and a refund of approximately $2.0 million to ATCO Gas' north customers. A decision from the AEUB is expected in the second quarter of 2005.

ATCO Pipelines

In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress.

In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

ATCO Pipelines' December 2, 2003, July 2, 2004, and July 13, 2004, decisions are referred to in this MD&A as the "ATCO Pipelines Decision".

The AEUB has announced that it will hold a hearing to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. This hearing is not expected to be held until 2006.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term and non-recourse debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Cash flow from operations for the three months ended December 31, 2004, increased by $11.1 million to $164.4 million, primarily due to:

- increased availability incentives in Alberta Power (2000), primarily due to availability incentive payments received for improved plant availability; and
- a refund to customers by ATCO Pipelines as a result of a change in income tax methodology as directed by the AEUB in the ATCO Pipelines Decision, which reduced cash flow from operations in 2003 by $5.4 million (the "ATCO Pipelines Refund").

This increase was partially offset by:

- a refund to customers by ATCO Gas as a result of a change in income tax methodology as directed by the AEUB in the ATCO Gas Decision, which reduced cash flow from operations in 2004 by $16.5 million (the "ATCO Gas Refund").

Cash flow from operations for the year ended December 31, 2004, increased by $12.5 million to $538.3 million, primarily due to:

- increased availability incentives in Alberta Power (2000);
- the ATCO Pipelines Refund.

This increase was partially offset by:

- the ATCO Gas Refund.

Investing for the three months ended December 31, 2004, increased by $0.2 million to $125.2 million, primarily due to:

- decreased proceeds on disposal of property, plant and equipment;
- changes in non-cash working capital ; and
- reductions in non-current deferred electricity costs.

This increase was partially offset by:

- lower capital expenditures.

Capital expenditures for the three months ended December 31, 2004, decreased by $27.6 million to $149.1 million, primarily due to:

- lower investment in regulated electric transmission and non-regulated power generation projects.

This decrease was partially offset by:

- increased investment in regulated natural gas transportation and distribution projects.

Investing for the year ended December 31, 2004, increased by $35.3 million to $469.3 million, primarily due to:

- higher capital expenditures;
- decreased proceeds on disposal of property, plant and equipment; and
- reductions in non-current deferred electricity costs.

This increase was partially offset by:

- changes in non-cash working capital; and
- proceeds from the Transfer of the Retail Energy Supply Businesses.

Capital expenditures for the year ended December 31, 2004, increased by $39.8 million to $535.5 million, primarily due to:

- increased investment in regulated electric transmission projects.

This increase was partially offset by:

- lower investment in non-regulated power generation projects.

During the three months ended December 31, 2004, the Corporation **issued**:

- $100.0 million of 5.096% Debentures due November 18, 2014; and
- $200.0 million of 5.896% Debentures due November 20, 2034.

During the three months ended December 31, 2004, the Corporation **redeemed**:

- $96.0 million of notes payable;
- $36.8 million of long term debt; and
- $8.8 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $158.4 million.

During the year ended December 31, 2004, the Corporation **issued**:

- $180.0 million of 5.432% Debentures due January 23, 2019;
- $100.0 million of 5.096% Debentures due November 18, 2014;
- $200.0 million of 5.896% Debentures due November 20, 2034;
- $59.8 million of other long term debt; and
- $10.0 million of non-recourse long term debt.

During the year ended December 31, 2004, the Corporation **redeemed**:

- $100.0 million of 8.73% Debentures 1994 Series due June 1, 2004;
- $68.6 million of other long term debt; and
- $49.2 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $332.0 million.

A planned issue of $180.0 million of debentures by CU Inc. in 2003 was deferred until January 2004 pending clarification of one of the Corporation's credit ratings. As a result of the uncertainty surrounding the timing of the receipt of the credit rating, the Corporation utilized its cash resources in late 2003 to temporarily pay down outstanding debt.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately $475 million in 2005. These expenditures are uncommitted and relate primarily to utility operations.

Contractual obligations for the next five years and thereafter are as follows:

Contractual Obligations	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
	Payments Due by Period ($ Millions)				
Long term debt	2,176.3	130.3	241.0	225.0	1,580.0
Non-recourse long term debt	811.5	50.6	120.9	158.0	482.0
Operating leases	67.9	15.0	26.7	16.8	9.4
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	7.0	1.4	1.4	1.4	2.8
Alberta Power (2000) coal purchase contracts (2)	881.7	43.5	90.6	96.1	651.5
Alberta Power (2000) capital expenditures (3)	9.7	9.7	-	-	-
ATCO Power natural gas fuel supply contracts (4)	367.0	49.0	111.3	110.9	95.8
ATCO Power operating and maintenance agreements (5)	175.1	16.4	30.3	34.0	94.4
ATCO Power capital expenditures (6)	6.4	6.4	-	-	-
ATCO Electric capital expenditures (7)	17.8	17.8	-	-	-
Other	16.8	16.8	-	-	-
Total	4,537.2	356.9	622.2	642.2	2,915.9

Notes:

(1) *ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate mostly to storage purchases and operational contracts pertaining to the Carbon storage facility, which was not included in the Transfer of the Retail Energy Supply Businesses to DEML and continues to be subject to AEUB regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2004, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. The cost of natural gas purchased under these obligations is recoverable from ATCO Gas' customers.*

(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.*

(3) *Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.*

(4) *ATCO Power has various contracts to purchase natural gas for its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 73% of these costs. The balance of 27%, related to ATCO Power's Barking generating plant, is currently being recovered through merchant sales in the U.K. electricity market.*

(5) *ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.*

(6) *ATCO Power has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.*

(7) *ATCO Electric has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.*

At December 31, 2004, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
		($ Millions)	
Long term committed	326.0	12.0	314.0
Short term committed	614.1	22.3	591.8
Uncommitted	69.0	11.4	57.6
Total	1,009.1	45.7	963.4

In the third quarter of 2004, following a review of ongoing cash requirements, the Corporation reduced its long term committed lines by $25.0 million, its short term committed lines by $9.6 million and its uncommitted lines by $108.4 million. These reductions were due primarily to reduced credit needs in CU Inc. following the Transfer of the Retail Energy Supply Businesses earlier in the year.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

Future income tax liabilities of $222.4 million at December 31, 2004, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2003, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 19, 2004. Over the life of the bid, 73,600 shares were purchased, of which 56,600 were purchased in 2003 and 17,000 were purchased in 2004. On May 20, 2004, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid will expire on May 19, 2005. From May 20, 2004, to February 23, 2005, 128,400 shares have been purchased, all of which were purchased in 2004.

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B shares. In 2004, the Corporation increased the dividends on Class A and Class B shares by $0.08 per share, the same increase as in 2003. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2005, the **quarterly dividend** payment has been increased by $0.02 to $0.55 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

On January 16, 2004, CU Inc. filed a base shelf prospectus which permits CU Inc. to issue up to an aggregate of $750.0 million of debentures over the twenty-five month life of the prospectus.

- On January 23, 2004, CU Inc. issued $180.0 million of 5.432% Debentures due January 23, 2019, at a price of 100 to yield 5.432%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.
- On November 18, 2004, CU Inc. issued $100.0 million of 5.096% Debentures due November 18, 2014, at a price of 100 to yield 5.096% and $200.0 million of 5.896% Debentures due November 20, 2034, at a price of 100 to yield 5.896%. The proceeds of the issues were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

OUTSTANDING SHARE DATA

At February 23, 2005, the Corporation had outstanding 41,430,193 Class A shares and 22,014,242 Class B shares.

The owners of the Class A shares and the Class B shares are entitled to share equally, on a share for share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The owners of the Class B shares are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Corporation, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A shares are entitled to exchange their shares for Class B shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Corporation. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 3,200,000 Class A shares reserved for issuance in respect of options under the Corporation's stock option plan, 1,467,350 Class A shares are available for issuance at December 31, 2004. Options may be granted to directors, officers and key employees of the Corporation and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 23, 2005, options to purchase 824,900 Class A shares were outstanding.

TRANSACTIONS WITH RELATED PARTIES

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $1.8 million, recovered administrative expenses totaling $2.7 million, and incurred administrative expenses and corporate signature rights totaling $7.1 million. The Corporation also incurred advertising and promotion expenses from an entity related through common control totaling $1.1 million. These transactions are in the normal course of business and under normal commercial terms.

BUSINESS RISKS

On February 16, 2005, the Kyoto Protocol came into effect. The Corporation is unable to determine what impact, if any, the protocol will have on its operations as the Government of Canada has not yet released its implementation plan. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

Regulated Operations

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Transfer of the Retail Energy Supply Businesses

Although ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, ATCO Gas and ATCO Electric remain legally obligated to perform these functions if DEML fails to perform. If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric. In the event of a reversion of such functions, ATCO Gas and ATCO Electric could incur costs related to commodity procurement, transportation and delivery charges and various regulatory costs.

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

As a result of the agreements with DEML, ATCO Gas and ATCO Electric are no longer involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return.

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

Late Payment Penalties on Utility Bills

As a result of recent decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

Alberta Power (2000)

Included in regulated operations are the generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and December 31, 2020.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPA's were based.

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

At December 31, 2004, the Corporation had recorded $46.1 million of deferred availability incentives.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

In August 2004, an arbitration tribunal appointed under the Battle River Power Purchase Arrangement ("Battle River PPA") determined that Alberta Power (2000) was entitled to recover $10.4 million of availability penalty payments, plus interest, from EPCOR Utilities Inc. ("EPCOR"), the counterparty to the Battle River PPA, due to short term curtailed plant production during the first quarter of 2003 caused by unprecedented drought conditions. The $10.4 million of availability penalty payments plus interest, less costs associated with the arbitration proceedings, was recorded in Alberta Power (2000)'s deferred availability incentive balance sheet account and had no effect on Alberta Power (2000)'s 2004 earnings.

In June and July 2004, the Battle River generating plant's water levels were below those of 2003, which required the Corporation to limit generation to avoid exceeding the environmental license temperature limitations. The Corporation made force majeure claims for the period June 24, 2004, to July 4, 2004, and the period July 13, 2004 to July 26, 2004. The Corporation claimed $7 million with respect to these claims and was successful in reaching a negotiated settlement with EPCOR and the Alberta Balancing Pool in December 2004 for $5.2 million. The remaining $1.8 million and related costs of $0.2 million were recorded as a reduction to Alberta Power (2000)'s deferred availability incentive balance sheet account. The settlement had no effect on Alberta Power (2000)'s 2004 earnings.

Non-Regulated Operations

The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which they operate.

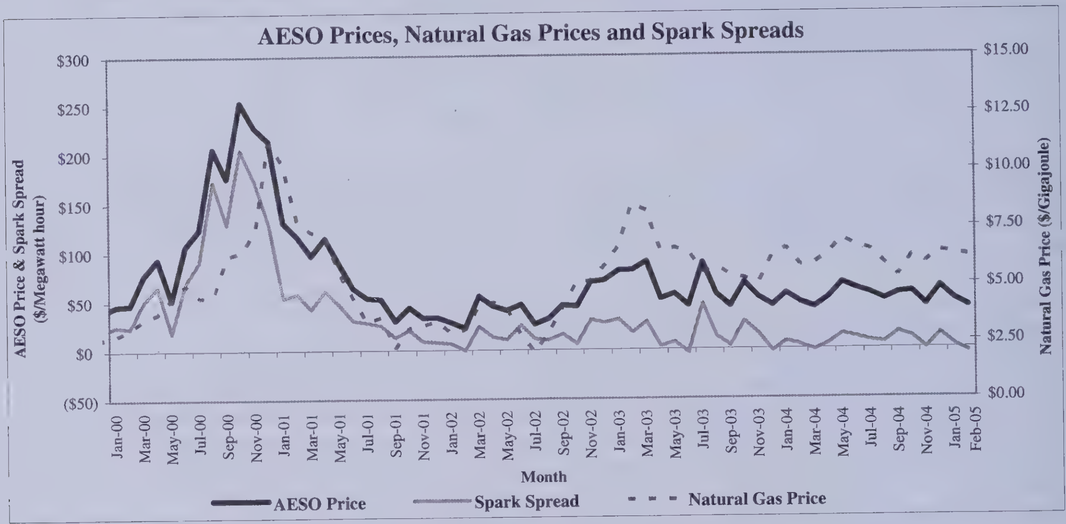
ATCO Power

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and small hydro plants. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2004, sales from approximately 72% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 28% consisted primarily of sales to the AESO. In 2005, the portion of generating capacity subject to long term agreements is expected to be approximately 73%, while the remaining 27% is expected to consist primarily of sales of electricity to the AESO. These sales are dependent on prices in the Alberta electricity spot market. The majority of the electricity sales to the AESO are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in

Alberta, a strong correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

AESO electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2005.



Changes in AESO electricity prices, natural gas prices and related spark spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. It is the Corporation's policy to continually monitor the status of its non-regulated electrical generating capacity that is not subject to long term commitments.

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) Equity contributions – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2004, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is anticipated to be $8.7 million.

b) Project cash flows – Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts for the Scotford project and 48 megawatts for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2004, no amounts were outstanding under the guarantee.

c) Reserve amounts – Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2004, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
	($ Millions)	
ATCO Power Alberta Limited Partnership ("APALP") project financing	Nil (1)	13.7
Joffre project financing	Nil (2)	4.2
Muskeg River project financing	Nil (1)	5.1
Scotford project financing	Nil (1)	5.6

Notes:
(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $2.7 million met with project cash flows.

d) Prepaid operating and maintenance fee – Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2004, the maximum value of the guarantee is $32.4 million.

e) Purchase project assets – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2004, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts. In addition, Canadian Utilities Limited has posted acceptable credit support in the amount of $2.2 million with respect to builders' liens filed against the Cory Project.

ATCO Power (80%) and ATCO Resources Ltd. (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power. The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Contingencies

The Corporation is party to a number of disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

Insurance Coverage

A number of U.S. insurance companies are the subject of lawsuits and investigations into their business and accounting practices by the Attorney General of the State of New York and the U.S. Securities and Exchange Commission. Certain of these insurers provide a portion of the Corporation's insurance coverage. The Corporation is unable at this time to determine what impact, if any, these investigations may have on the ability of the insurers mentioned to pay any corporate insurance claims which may arise.

OFF-BALANCE SHEET ARRANGEMENTS

Unrecorded future income tax liabilities of the regulated operations amounted to $165.3 million at December 31, 2004. This balance includes $38.8 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. The remainder, amounting to $126.5 million, is expected to be recovered from utility customers through inclusion in future rates. Expected future recoveries relating to tax loss carryforwards have been recorded in the amount of $0.9 million, of which $0.1 million begins to expire in 2007 and $0.8 million does not expire. In addition, there are tax loss carryforwards of $1.2 million for which no tax benefit has been recorded. These losses begin to expire in 2006.

In addition, the Corporation uses various derivative instruments to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. Note 20 to the financial statements sets out the instruments in place at December 31, 2004.

Other than the foregoing, the Corporation does not have any off-balance sheet arrangements that have, or are likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation's critical accounting estimates are discussed below.

Deferred Availability Incentives

As noted previously in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2004, the Corporation had recorded $46.1 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to $7.6 million in 2004.

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $4.1 million, whereas the low case scenario would have resulted in lower revenues of approximately $2.9 million.

Employee Future Benefits

The Corporation's employee future benefits disclosures are based on three critical accounting estimates: (1) the expected long term rate of return on plan assets; (2) the liability discount rate; and, (3) the long term inflation rate.

The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 6.25% at the beginning of 2004, resulted in an expected long term rate of return of 7.25% for 2004. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

The liability discount rate reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate used to calculate the cost of benefit obligations for the three months and the year ended December 31, 2004, was 6.25%, the same rate that was used at the end of 2003. The liability discount rate used to value the benefit obligations at December 31, 2004, was 5.9%, a decrease of 0.35% from the rate used to calculate the cost of benefit obligations during 2004. This lower rate will be used to calculate the cost of benefit obligations in 2005.

The expected long term rate of return has declined over the past three years, from 8.1% in 2001 to 7.25% in the year ended December 31, 2004. The result has been a decrease in the expected return on plan assets. The difference between the expected return and the actual return on plan assets results in an experience gain or loss on plan assets. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 5.9% at

December 31, 2004. The effect of this change has been to increase the accrued benefit obligations, resulting in experience losses in 2002, 2003 and 2004. In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the cumulative experience losses in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization during the three months and the year ended December 31, 2004.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three months and the year ended December 31, 2004, are as follows: for drug costs, 9.9% starting in 2004 grading down over 9 years to 4.5%, and for other medical and dental costs, 4.0% for 2004 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AEUB decision to record the costs of employee future benefits when paid rather than accrued. Therefore, a significant portion of the benefit plans expense or income is unrecognized by the regulated operations, excluding Alberta Power (2000).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2004 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2004 Pension Benefit Plans		**2004 Other Post Employment Benefit Plans**	
	Accrued Benefit Obligation	**Benefit Plan Cost (Income)**	**Accrued Benefit Obligation**	**Benefit Plan Cost (Income)**
	($ Millions)			
Expected long term rate of return on plan assets				
1% increase (1)	-	(3.3)	-	-
1% decrease (1)	-	3.3	-	-
Liability discount rate				
1% increase (1)	(51.8)	(4.8)	(2.6)	(0.2)
1% decrease (1)	65.3	5.9	3.3	0.3
Future compensation rate				
1% increase (1)	17.9	2.6	-	-
1% decrease (1)	(13.8)	(2.0)	-	-
Long term inflation rate				
1% increase (1)(2)(3)	21.5	2.8	2.9	0.5
1% decrease (1) (3)	(38.0)	(5.0)	(2.4)	(0.4)

Notes:

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost (income), which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefits plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2004, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations on accounting for asset retirement obligations as described below. The prior year's financial statements have been restated for the change in the method of accounting for asset retirement obligations.

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

The effect of adopting these recommendations is presented as increases (decreases) below:

	For the Three Months Ended December 31		**For the Year Ended December 31**	
($ Millions)	**2004**	2003	**2004**	2003
	(unaudited)			
Statement of earnings				
Site restoration and removal costs, included in operation and maintenance	**-**	-	**-**	(0.2)
Depreciation and amortization	**(0.2)**	(0.3)	**(0.8)**	(1.5)
Accretion expense, included in depreciation and amortization	**0.5**	0.4	**1.9**	1.8
Income taxes	**(0.1)**	-	**(0.2)**	(0.1)
Earnings attributable to Class A and Class B shares	**(0.2)**	(0.1)	**(0.9)**	-

	January 1 2003
	($ Millions)
Balance sheet	
Retirement assets and site restoration and removal costs, included in property, plant and equipment	24.2
Asset retirement obligations, included in deferred credits	30.1
Accrual for future removal and site restoration costs, included in deferred credits	(3.3)
Future income tax liabilities	0.5
Retained earnings at beginning of period	(3.1)

Changes in asset retirement obligations are summarized below:

($ Millions)	For the Three Months Ended December 31 2004	2003	For the Year Ended December 31 2004	2003
	(unaudited)			
Obligations at beginning of period	**34.2**	31.5	**32.3**	30.1
Obligations incurred	**-**	0.4	**0.5**	0.4
Accretion expense	**0.5**	0.4	**1.9**	1.8
Obligations at end of period	**34.7**	32.3	**34.7**	32.3

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $93 million, which will be incurred between 2005 and 2052. A weighted average discount rate of 5.9% was used to calculate the fair value of the asset retirement obligations.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. This change in accounting had no effect on earnings for the three months and year ended December 31, 2004.

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for stock based compensation. These recommendations require the expensing of stock options granted on and after January 1, 2002. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital. No compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by the recommendations. This retroactive change in accounting had no effect on earnings for the three months ended December 31, 2004, and reduced earnings for the year ended December 31, 2004, by $0.1 million with no effect on earnings per share in either period, reduced earnings for the three months and year ended December 31, 2003 by $0.1 million and $0.2 million, respectively, with no effect on earnings per share in either period, and resulted in a charge of $0.1 million to retained earnings at January 1, 2003. The prior year's financial statements have been restated for the change in the method of accounting for stock options.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations that define the primary sources of GAAP. Adoption of these recommendations had no effect on earnings for the three months and year ended December 31, 2004. While CICA recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP. Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the regulator renders a subsequent decision. The Corporation anticipates that there would be no material differences between the amounts approved by the regulator for collection or refund and the amounts included in assets or liabilities on the balance sheet. The Corporation has chosen to retain its existing accounting policies, as permitted by CICA recommendations that define the primary sources of GAAP, pertaining to regulatory decisions that give rise to deferred assets or liabilities.

Effective January 1, 2005, the Corporation intends to prospectively adopt the CICA's accounting guideline on the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities and, if so, to consolidate them. The Corporation is currently evaluating the impact of the guideline.

February 23, 2005

Consolidated Five-Year Financial Summary

(Millions of Canadian dollars, except as indicated)		**2004**	2003	2002	2001	2000
EARNINGS						
Revenues		**3,089.5**	3,742.6	2,975.9	3,513.6	2,924.5
Operating expenses (1)		**2,185.6**	2,868.7	2,169.8	2,695.4	2,087.0
Depreciation and amortization (1)		**291.5**	269.2	243.9	243.4	240.7
Interest		**203.7**	190.3	184.1	198.7	196.2
Dividends on preferred shares		**-**	-	-	-	0.6
Interest and other income		**(94.1)**	(33.4)	(136.2)	(41.4)	(23.5)
Income taxes (1)		**158.0**	155.6	190.0	164.2	179.9
Dividends on equity preferred shares		**35.8**	33.1	18.2	17.0	16.8
Earnings attributable to Class A and Class B shares (1)		**309.0**	259.1	306.1	236.3	226.8
SEGMENTED EARNINGS						
Utilities (2)		**168.7**	121.3	177.8	99.9	108.4
Power generation (1)		**80.0**	92.8	76.2	93.5	95.1
Global enterprises (1) (2)		**72.1**	56.1	45.5	34.8	22.7
Corporate and other/eliminations (1) (2)		**(11.8)**	(11.1)	6.6	8.1	0.6
Earnings attributable to Class A and Class B shares (1)		**309.0**	259.1	306.1	236.3	226.8
BALANCE SHEET						
Property, plant, and equipment		**5,045.3**	4,835.4	4,681.2	4,384.7	4,028.2
Total assets		**6,463.1**	6,096.5	5,958.6	5,425.2	5,424.7
Capitalization:						
Notes payable		**-**	-	-	4.6	197.1
Long term debt		**2,171.0**	1,805.3	1,916.9	1,855.9	1,865.5
Non-recourse long term debt		**760.9**	806.1	821.1	673.8	360.0
Equity preferred shares		**636.5**	636.5	486.5	336.5	336.5
Share owners' equity (1) (3)		**2,117.7**	1,948.5	1,827.0	1,639.5	1,523.0
Total capitalization (1)		**5,686.1**	5,196.4	5,051.5	4,510.3	4,282.1
CASH FLOWS						
Operations		**538.3**	525.8	504.6	532.2	490.2
Purchase of property, plant and equipment		**535.5**	495.7	569.8	735.3	451.3
Financing (excluding Class A and B dividends)		**333.8**	(10.6)	384.3	62.0	189.5
Class A and B dividends		**134.4**	129.3	124.2	119.0	114.0
CLASS A & B SHARES						
Shares outstanding at end of year (3) (thousands)		**63,392**	63,384	63,412	63,317	63,306
Return on equity (3)		**15.2%**	13.7%	17.7%	14.9%	15.4%
Earnings per share (3) ($)		**4.88**	4.09	4.83	3.73	3.58
Dividends paid per share (3) ($)		**2.12**	2.04	1.96	1.88	1.80
Equity per share (3) ($)		**33.41**	30.74	28.81	25.89	24.06
Stock market record - Class A non-voting shares ($)	High	**64.00**	59.60	60.10	56.05	51.45
	Low	**51.42**	45.10	48.80	44.50	31.00
	Close	**60.32**	57.86	51.21	49.75	51.00
Stock market record - Class B common shares ($)	High	**63.90**	58.75	60.50	54.20	51.15
	Low	**51.40**	45.50	49.00	44.95	31.10
	Close	**63.90**	58.00	52.65	49.00	50.55

(1) Figures for 2000-2003 have been restated for the retroactive changes in method of accounting for asset retirement obligations and stock options.

(2) Segmented earnings for 2000-2003 have been restated to reflect changes to the management reporting structure announced in August 2004.

(3) Includes Class A non-voting shares and Class B common shares.

Consolidated Five-Year Operating Summary

(Millions of Canadian dollars, except as indicated)	**2004**	2003	2002	2001	2000
Utilities					
Natural gas operations					
Purchase of property, plant and equipment	**154.3**	141.0	103.1	84.6	87.6
Pipelines (thousands of kilometres)	**34.8**	34.2	33.7	33.5	33.5
Maximum daily demand (terajoules)	**2,049**	1,831	1,670	1,470	1,737
Natural gas sold [(1)] (petajoules)	**103**	198	201	187	209
Natural gas transported [(1)] (petajoules)	**120**	32	31	22	18
Total system throughput (petajoules)	**223**	230	232	209	227
Average annual use per residential customer (gigajoules)	**134**	134	136	131	148
Degree days - Edmonton [(2)]	**3,985**	4,245	4,274	3,661	4,210
- Calgary [(3)]	**3,978**	4,291	4,470	3,994	4,441
Customers at year-end (thousands)	**914.3**	887.8	862.0	837.7	816.1
Electric operations					
Purchase of property, plant and equipment	**223.4**	171.6	162.4	154.2	114.5
Power lines (thousands of kilometres)	**68.0**	67.0	67.1	64.2	58.6
Electricity distributed (millions of kilowatt hours)	**9,910**	9,768	10,224	10,108	10,392
Average annual use per residential customer (kWh)	**7,475**	7,261	7,445	7,270	7,444
Customers at year-end (thousands)	**206.2**	202.3	197.8	192.0	191.0
Pipeline operations					
Purchase of property, plant and equipment	**47.9**	33.6	47.3	77.4	63.5
Pipelines (thousands of kilometres)	**8.3**	8.3	8.3	8.2	7.9
Contract demand for pipelines system access (terajoules/day)	**4,606**	4,599	4,890	4,876	4,559
Power Generation					
Purchase of property, plant and equipment	**77.0**	131.7	236.0	384.2	155.5
Generating capacity (thousands of kilowatts)	**2,474**	2,397	2,036	2,036	668
Global Enterprises					
Purchase of property, plant and equipment	**14.5**	15.5	11.5	34.5	30.1
Natural gas processed (Mmcf/day)	**427**	399	420	429	366
Natural gas gathering lines (kilometres)	**1,000**	1,000	940	940	670

(1) Effective May 2004, with the transfer of the retail energy supply businesses, ATCO Gas' existing sales service customers became transportation service customers.

(2) Degree days - Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.

(3) Degree days - Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

GENERAL INFORMATION

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., M.D.T. Wednesday, May 5, 2005 at The Fairmont Hotel Macdonald, 10065-100 Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A Non-Voting and
Class B Common Shares and
Second Preferred
(Series Q, R, S, W and X) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/Calgary/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/Calgary/Vancouver

STOCK EXCHANGE LISTINGS
Class A non-voting Symbol CU.NV
Class B common Symbol CU.X
Listing: The Toronto Stock Exchange

CUMULATIVE REDEEMABLE SECOND PREFERRED SHARES
5.90% Series Q CU.PR.T
5.30% Series R CU.PR.V
6.60% Series S CU.PR.D
5.80% Series W CU.PR.A
6.00% Series X CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS
Annual Reports to Share Owners and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:
ATCO Ltd. & Canadian Utilities Limited
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.canadian-utilities.com

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning shares should be directed to:
CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
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